financial report 2007

Freehold

ROYALTY TRUST

Freehold Royalty Trust is one of the largest owners of freehold mineral rights in Canada. Our mission is to effectively manage our assets to consistently deliver attractive returns to Unitholders over the long term.

mission

Our vision is to be recognized as the preeminent royalty-focused oil and gas investment in Canada.

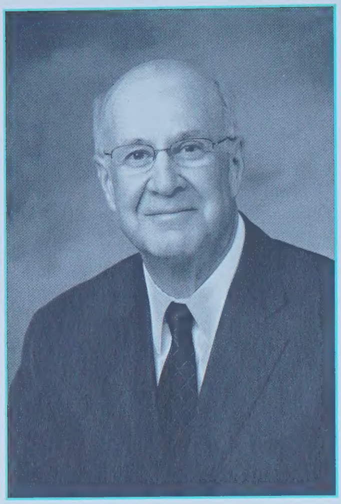
strategy

- Actively manage our large portfolio of oil and gas royalty interests by maintaining an aggressive audit program to ensure that royalty income is correctly calculated and paid
- Successfully develop our working interest properties to sustain production and extend reserve life, while maintaining a low risk profile
- Acquire appropriate assets, with a bias toward royalty interests, to provide long-term growth in the value of the Trust
- Maintain a conservative approach to debt management to provide maximum financial flexibility, while maintaining stable distributions

financial highlights

FINANCIAL ($000s, except as noted)	2007	2006	Change
Gross revenue	152,184	143,067	6%
Net income (loss)	(1,192)	45,181	-103%
Per Trust Unit, basic and diluted ($) [1]	(0.02)	0.92	-102%
Funds generated from operations	121,008	119,849	1%
Per Trust Unit ($) [1]	2.46	2.44	1%
Distributions declared	94,545	103,100	-8%
Per Trust Unit ($) [2]	1.92	2.10	-9%
Capital expenditures	12,167	11,446	6%
Property and royalty acquisitions	90,456	5,382	1,581%
Long-term debt, period end	178,000	100,000	78%
Unitholders' equity, period end	251,106	344,448	-27%
Trust Units outstanding, period end (000s)	49,317	49,174	–
Weighted average (000s)	49,228	49,086	–
OPERATING			
Production (boe/d) [3]	8,484	8,412	1%
Average price realizations ($/boe) [3]	48.63	46.07	6%
Operating netback ($/boe) [3]	43.54	42.64	2%
Reserves (Mboe) [3, 4]	27,963	28,012	–
Land holdings (gross acres) (000s)	2,380	2,069	15%
Undeveloped land (gross acres) (000s)	589	598	-2%

1. Based on the weighted average number of Trust Units outstanding during the year.
2. Based on the number of Trust Units issued and outstanding at each record date.
3. To provide a single unit of production for analytical purposes, natural gas production and reserve volumes are mathematically converted to equivalent barrels of oil (boe) at a ratio of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The boe ratio approximates an equivalent energy value, useful for comparative measures, but may not accurately reflect individual product values.
4. Net proved plus probable reserves, evaluated under National Instrument 51-101.



David J. Sandmeyer, President and CEO

message to unitholders

As Freehold enters its 12th year of operations, I am pleased to report another year of solid performance for the Trust. In 2007, oil prices demonstrated unparalleled strength as global supply struggled to keep pace with demand growth. However, the Canadian dollar also strengthened significantly in 2007, reducing Canadian dollar realizations. Natural gas prices remained under pressure due to North American supply and demand imbalances. Within this environment, our operating netbacks remained strong, at $43.54 per barrel of oil equivalent (boe), compared with $42.64 per boe last year, while production remained level year over year. Funds generated from operations totalled $121 million ($2.46 per Trust Unit), a slight improvement from 2006.

Net income was reduced to a loss of $1.2 million with the recording of a $47.6 million future income tax expense related to the trust taxation legislation that takes effect in 2011. This provision was a non-cash expense relating to temporary differences between accounting versus tax depreciation rates and had no impact on our cash flows or our cash available for distribution. Distributions for 2007 totalled $1.92 per Trust Unit, the second highest level in our history.

From inception to March 15, 2008, we have paid out more than $602 million in distributions ($16.67 per Trust Unit), contributing to a total return of 614% (distributions reinvested plus unit price appreciation).

ADDED 3.1 MMBOE OF RESERVES AND REPLACED 100% OF 2007 PRODUCTION

In 2007, we spent $102.6 million on development activities and acquisitions, adding 3.1 million boe of net proved plus probable reserves at an average cost of $32.15 per boe. These activities replaced 100% of our 2007 production and contributed to a three-year average recycle ratio of 1.7 times. The recycle ratio is a key measure of the efficiency with which new reserves are added and is indicative of the value created by investment activities as it represents the cash flow generated for each dollar invested.

Since 1996, operators leasing our royalty lands have drilled a total of 6,187 wells – activity that has helped to offset the depletion of our production and reserves – at no cost to us.

HEALTHY DEVELOPMENT ACTIVITY CONTINUES ON OUR ROYALTY LANDS

Although drilling on our royalty lands declined 8% year over year, we fared better than industry in general, which experienced an overall 19% decline in drilling activity in 2007. Considering the current industry slowdown, we are very encouraged by the tangible evidence of ongoing development potential on our royalty lands. At year-end 2007, there were 92 (4.1 equivalent net) licensed drilling locations on our royalty lands, compared with 119 (6.1 equivalent net) locations at December 31, 2006. We are also seeing an increase in uphole recompletions in wells that have produced out in lower formations. We count among our active lessees some of the largest oil and gas producers in the industry, and we believe these companies will continue to be active on our royalty lands.

ACQUISITIONS INCREASE LAND HOLDINGS TO 2.4 MILLION GROSS ACRES

During 2007, we completed two royalty acquisitions, adding approximately 319,000 gross acres of land in Alberta and Saskatchewan. Our total land holdings now span almost 2.4 million gross acres across western Canada and in southern Ontario. Production from these acquired lands receives higher netbacks as it is unencumbered by operating and capital costs and third party royalty expenses. Going forward, we believe that some exploration and production companies and other oil and gas trusts may sell their non-core royalty interests to fund capital expenditure programs or reduce debt. This should present opportunities for us to acquire additional royalty interests.

PURSUING NEW WORKING INTEREST OPPORTUNITIES

In 2007, activities on our working interest properties focused on two key areas - Hayter, Alberta and Southeast Saskatchewan. In Southeast Saskatchewan, recent drilling successes have identified additional infill locations. Recently, we have selectively chosen to take working interest positions on our unleased mineral title lands where the economics of such participation are attractive. In these instances, our netbacks are high because we own the mineral title and our share of production is royalty free.

ALBERTA CROWN ROYALTY AND FEDERAL TAX CHANGES ON THE HORIZON

On October 25, 2007, the Government of Alberta announced its "New Royalty Framework" for oil and gas royalty policy effective January 1, 2009. The new royalty regime will have a sliding scale formula based on both commodity prices and well productivity. The royalty rate changes will see the oil and gas industry paying higher royalties on production from Alberta Crown lands beginning in 2009. This will no doubt have a negative impact on producers' future cash flows. However, we expect to see little direct impact on Freehold's current producing wells, given the mature nature of most of our producing assets and the small proportion of our production (about 10%) that is subject to Alberta Crown royalties.

In October 2006, the federal government unexpectedly announced its plan to impose a tax on distributions from certain publicly-traded specified income flow-through (SIFT) entities beginning January 1, 2011. In response to the tax changes, we continue to evaluate the options available to us, but in the interim we plan to retain the flow-through advantage of our trust structure unless there is a compelling reason for a faster transition to an alternative structure. On February 26, 2008, the Minister of Finance delivered the federal government's 2008 budget. Rather than a flat provincial rate of 13% as previously announced, the budget proposes that the provincial component of the SIFT tax be based on actual provincial corporate tax rates under a formula giving equal weight to province-by-province payrolls and revenues. This is a positive development for Alberta-based income trusts.

INDUSTRY UNCERTAINTY CONTINUES IN THE NEAR TERM

In North America, the natural gas market has been kept well supplied by both liquefied natural gas (LNG) imports and an active land drilling program in the United States. Continued geopolitical uncertainty and strong global demand growth are expected to keep crude oil prices high, while storage levels and weather will be the key demand factors for natural gas prices.

In western Canada, drilling activity is forecast to decline from 2007 levels in response to weak natural gas markets experienced in 2007, high operating costs, and the strength of the Canadian dollar. As well, the new Alberta Crown royalty structure could significantly change the economics of future exploration and development activities in the province. A number of large exploration and production companies have announced reduced capital spending plans, especially in gas-prone areas of Alberta. However, the recent decline in natural gas storage levels and corresponding improvement in natural gas prices may result in higher activity levels in the last half of 2008.

Most of Freehold's gas-prone lands are located in southeastern Alberta and southwestern Saskatchewan, where productivity per well is low, relative to other areas of the Western Canada Sedimentary Basin. In these areas, natural gas pricing has the most influence on producers' drilling decisions. A dramatic, prolonged reduction in industry drilling would likely be reflected on our royalty lands, but the magnitude of any potential impact on Freehold's future production and reserves is not possible to predict.

EXECUTING A CONSISTENT STRATEGY FOR SUSTAINABLE RESULTS

Our distribution remains fixed at $0.15 per month subject to quarterly review by our Board. Our distribution policy takes into consideration forecasted cash provided by operating activities, debt levels, and capital expenditures. We have a declining asset base, and ongoing development activities and acquisitions are necessary to replace production and add reserves. The success of these activities, along with commodity prices, are the main factors influencing the sustainability of our distributions.

We have allocated $10.6 million in capital for further development of our working interest properties in 2008. And with our recent acquisitions also contributing to our results, we expect production this year to average 8,200 boe per day.

We remain committed to maximizing sustainable cash distributions over the long term by actively managing our large portfolio of oil and gas royalty interests, successfully developing our working interest properties to sustain production and extend reserve life, and acquiring appropriate assets to provide long-term growth in the value of the Trust. We will continue to focus on the successful execution of this strategy.

On January 31, 2008, Tullio Cedraschi retired as President and CEO of the CN Investment Division. His successor, Russell J. Hiscock, will become one of the two Manager-appointed directors of Freehold at our Annual Meeting on May 7, 2008 to replace Mr. Cedraschi. We look forward to welcoming Mr. Hiscock as a director. The Board is pleased to announce that Mr. Cedraschi has agreed to stand for election as an independent director at Freehold's Annual Meeting.

In closing, I would like to acknowledge and thank the employees of the Manager for their efforts on behalf of Freehold. I would also like to thank my fellow directors for their continued guidance and our Unitholders for their continued support.

On behalf of the Board of Directors of Freehold Resources Ltd.,

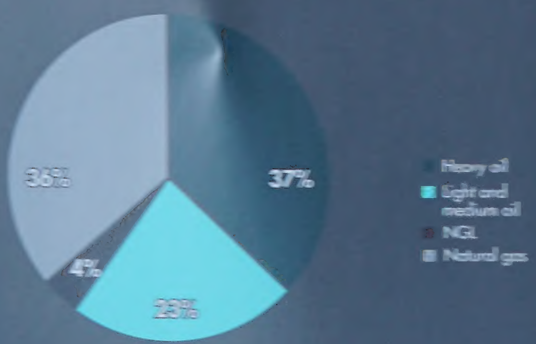
David J. Sandmeyer
President and Chief Executive Officer
March 14, 2008

2007 year in review

Average Benchmark Oil Prices

Average Benchmark Natural Gas Prices

Production Profile
(boe/d)



Distributions Declared
($/Trust Unit)

1. Distribution due to additional income earned in 2007

management's discussion and analysis

The following discussion is management's opinion about our consolidated operating and financial results, which include Freehold Resources Ltd., Freehold Royalty Trust and Petrovera Resources (a general partnership) for the year ended December 31, 2007 and previous periods, and the outlook for Freehold based on information available as at March 14, 2008.

The financial information contained herein has been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the years ended December 31, 2007 and 2006 and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This discussion and analysis should be read in conjunction with the audited financial statements and notes contained in this annual report. Additional information about us, including our annual information form, is available on SEDAR at www.sedar.com.

Forward-Looking Statements

This MD&A offers our assessment of Freehold's future plans and operations as at March 14, 2008, and contains forward-looking statements. Such statements are generally identified by the use of words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "plan", "intend", "believe", and similar expressions (including the negatives thereof). By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, taxation, royalties, regulation, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility, and our ability to access sufficient capital from internal and external sources. Risks are described in more detail in our Annual Information Form, which is available on our website.

You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. Except as required by law, we do not undertake to update these forward-looking statements.

Conversion of Natural Gas to Barrel of Oil Equivalent (boe)

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are mathematically converted to equivalent barrels of oil (boe). We use the international conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio approximates an equivalent energy value at the burner tip and does not represent a value equivalency at the wellhead or an economic value equivalency. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

Non-GAAP Measures

Within this MD&A, we refer to terms commonly used as key performance indicators in the oil and gas industry. We believe that operating netback, investor netback, and funds generated from operations are useful supplemental measures to analyze operating performance, leverage, and liquidity. However, these terms do not have any standardized meanings prescribed by Canadian GAAP and therefore may not be comparable with the calculations of similar measures for other entities.

Operating netback, which is calculated as average unit sales price less royalties and operating expenses; and investor netback, which deducts administrative and interest expense and income and capital taxes, represent the cash margin for product sold, calculated on a per boe basis. Funds generated from operations is a key measure of our ability to generate cash, finance operations, and pay monthly distributions. Funds generated from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash provided by operating activities, net income, or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds generated from operations throughout this report are based on cash provided by operating activities before changes in non-cash working capital as per the Statement of Cash Flows. Funds generated from operations per Trust Unit is calculated based on the weighted average number of Trust Units outstanding consistent with the calculation of net income per Trust Unit.

In addition, we refer to various per boe figures, such as revenues and costs, which are also considered non-GAAP measures but provide meaningful information on our operational performance. We derive per boe figures by dividing the relevant revenue or cost figure by the total volume of oil and gas production during the period, with natural gas converted to equivalent barrels of oil as described above.

BUSINESS OVERVIEW

Freehold Royalty Trust is structured as a mutual fund trust under the *Income Tax Act* (Canada). This enables us to return the majority of our income to Unitholders in a tax-effective manner. We receive revenue from oil and gas properties as reserves are produced over the economic life of the properties.

At December 31, 2007, our land holdings encompassed approximately 2.4 million gross acres including 589,099 gross acres of undeveloped land. Our mineral title lands, owned in perpetuity, cover about 549,800 gross acres. We have gross overriding royalty interests in approximately 1.6 million acres (including royalty assumption lands). In addition, we hold working interests in 207,428 gross (24,310 net) acres.

Our properties are geographically widespread throughout western Canada. We have interests in more than 25,000 wells and we receive royalty income from approximately 250 industry operators. Royalty rates vary from less than 1% (for some gross overriding royalties) to 22.5% (for lessor royalties). This diversity lowers our risk.

Mission, Vision and Strategy

Freehold Royalty Trust is pursuing the royalty advantage. We are one of the largest owners of freehold mineral rights in Canada. Our mission is to manage our assets effectively to consistently deliver attractive returns to Unitholders over the long term.

Our vision is to be recognized as the preeminent royalty-focused oil and gas investment in Canada.

To achieve our vision we will:

- Actively manage our large portfolio of oil and gas royalty interests by maintaining an aggressive audit program to ensure that royalty income due to the Trust is correctly calculated and paid.
- Successfully develop our working interest properties to sustain production and extend reserve life, while maintaining a low risk profile.
- Acquire appropriate assets, with a bias toward royalty interests, to provide long-term growth in the value of the Trust.
- Maintain a conservative approach to debt management to provide maximum financial flexibility with respect to acquisitions and development expenditures, while maintaining stable distributions.

The Royalty Advantage

Royalties offer the benefit of sharing in production revenue without exposure to the capital costs, operating costs, and environmental costs normally associated with oil and gas production. Our high percentage of royalty revenue (67% in 2007) results in high netbacks, which maximizes distributions to Unitholders.

On May 10, 2005, we acquired Petrovera Resources, a general partnership, for $351.7 million. The largest transaction in our history, Petrovera added critical mass to enhance stability of our distributions over the long term from royalty interest assets that were a very good fit with our existing portfolio. The acquisition doubled our royalty production and solidified our position as one of the largest holders of oil and gas royalties in Canada.

We further augmented our royalty lands in the third quarter of 2007. On August 31, 2007, we acquired gross overriding royalty (GORR) interests on 309,800 gross acres of land in Alberta and Saskatchewan for $57.6 million. Currently, 1,300 wells are producing on these lands. On September 5, 2007, we acquired a 7% GORR on 9,078 gross acres of land at Dixonville, Alberta, for $32.8 million.

The following analysis illustrates the advantage of our royalty lands from which we receive revenue but do not incur royalty expenses, operating expenses, site restoration expenses, or development expenditures. In 2007, royalty interests accounted for 67% of gross revenue and 77% of distributions.

2007 COMPONENTS OF DISTRIBUTIONS TO UNITHOLDERS

($000s, except as noted)	Royalty Interest Properties	Working Interest Properties	Total Trust
Gross revenue	101,976	50,208	152,184
Royalty expense	–	(5,003)	(5,003)
Freehold mineral tax	(1,008)	(252)	(1,260)
Net revenue	100,968	44,953	145,921
Operating expenses	–	(11,076)	(11,076)
	100,968	33,877	134,845
General and administrative expenses, less non-cash unit based compensation	(4,349)	(1,505)	(5,854)
Interest expense	(6,408)	(597)	(7,005)
Income and capital taxes	–	(179)	(179)
Expenditures on reclamation	–	(799)	(799)
	90,211	30,797	121,008
Reclamation fund withdrawal	–	329	329
Capital expenditures	–	(12,167)	(12,167)
Acquisitions	(90,456)	–	(90,456)
Changes in debt	74,834	3,166	78,000
Changes in working capital	(1,489)	(680)	(2,169)
Distributions declared	73,100	21,445	94,545
Percentage contribution	77%	23%	100%

The Manager

We do not operate any of our oil and gas assets, nor do we have any employees.

The Manager of Freehold is a wholly owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of Canadian National Railway Company). The Manager is responsible for the day-to-day management of the business of the Trust subject to the supervisory role of the Board. In exercising its powers and discharging its duties under the management agreement, the Manager must exercise the degree of care, diligence and skill that a reasonably prudent advisor and manager in respect of petroleum and natural gas properties in western Canada would exercise in comparable circumstances. The Manager recovers its costs and receives a quarterly management fee paid in Trust Units.

The management agreement has a term of three years and will automatically renew on November 26, 2010, unless terminated. The Manager provides certain administrative and support services to the Trust, including those necessary to:

- Ensure compliance with continuous disclosure obligations under applicable securities legislation.
- Provide investor relations services.
- Provide or cause to be provided to Unitholders all information to which Unitholders are entitled under the Trust Indenture.
- Call, hold and distribute materials including notices of meetings and information circulars in respect of all necessary meetings of Unitholders.
- Determine the amounts payable from time to time to Unitholders and arrange for distributions to Unitholders.
- Determine the timing and terms of future offerings of Trust Units, if any.
- Determine the terms and conditions upon which the Trust may acquire additional royalties.
- Determine the terms and conditions upon which the Trust may from time to time borrow money.

Health, Safety and Environment

Freehold is a member of the Canadian Association of Petroleum Producers (CAPP). We encourage our operators to participate and excel in the CAPP Stewardship Program by aligning their operations with industry best practices and communicating clearly that meeting or exceeding regulatory requirements is expected.

We are liable for our share of ongoing environmental obligations and for the ultimate reclamation of the working interest properties upon abandonment. We have no reclamation responsibilities on our royalty assets as these are the responsibility of the working interest owners. In 1996, we established a reclamation fund to ensure that required funds are available for future reclamation of working interest wells and facilities once they have reached the end of their economic life (see Reclamation Fund).

The Manager of Freehold has a comprehensive environment, health and safety program to protect the health and safety of its employees, contractors, and the public.

RESULTS OF OPERATIONS

2007 Highlights

- Gross revenue was $152.2 million, up 6%.
- Net income was reduced to a loss of $1.2 million ($(0.02) per Trust Unit) with the recording of a non-cash future income tax expense of $47.6 million related to the enactment of the federal government's specified income flow-through (SIFT) tax legislation.
- Funds generated from operations totalled $121.0 million ($2.46 per Trust Unit) , up 1%.
- Distributions to Unitholders totalled $1.92 per Trust Unit, down 9%.
- Production averaged 8,484 boe per day, up 1%.
- Price realizations averaged $48.63 per boe, up 6%.
- Operating netback averaged $43.54 per boe, up 2%.
- Capital expenditures totalled $12.2 million and acquisitions totalled $90.5 million.

Historical Performance Review

Our results are directly influenced by commodity prices, which are determined by supply and demand factors, weather, seasonality, global political events, general economic conditions, and changes in Canadian/U.S. dollar exchange rates.

SELECTED ANNUAL DATA

($000s, except as noted)	2007	2006	2005
Revenue, net of royalty expenses	145,921	139,236	133,323
Net income (loss)	(1,192)	45,181	58,346
Per Trust Unit, basic and diluted ($)	(0.02)	0.92	1.36
Total assets	504,200	474,228	534,078
Long-term debt	178,000	100,000	107,000
Total long-term liabilities	237,118	108,559	114,968
Distributions declared	94,545	103,100	84,810
Per Trust Unit ($) [1]	1.92	2.10	1.92

1. Based on the number of Trust Units issued and outstanding at each record date.

In 2007, cash provided by operating activities totalled $119.6 million, down by 9% from 2006. Funds generated from operations totalled $121.0 million ($2.46 per Trust Unit), up 1%. Net income for the year was reduced to a loss of $1.2 million ($(0.02) per Trust Unit) with the recording of a $47.6 million non-cash future income tax expense related to the substantive enactment of the SIFT tax legislation. This provision was a non-cash expense relating to temporary differences between accounting versus tax rates and had no impact on our cash provided by operating activities during the period.

In response to the SIFT tax changes, we continue to evaluate the options available to us, but in the interim we plan to retain the flow-through advantage of our trust structure unless there is a compelling reason for an earlier transition to an alternative structure. We remain committed to maximizing sustainable cash distributions over the long term by actively managing our large portfolio of oil and gas royalty interests, successfully developing our working interest properties to sustain production and extend reserve life, and acquiring appropriate assets to provide long-term growth in the value of the Trust. We will continue to focus on the successful execution of this strategy.

Quarterly variances in revenues, net income, and funds generated from operations are caused mainly by fluctuations in commodity prices, production volumes, and operating costs. Crude oil prices are generally determined by global supply and demand factors, but the variances do not have seasonable predictability. Natural gas prices are typically higher in winter months as heating demand rises, but this seasonality is significantly affected by weather conditions and North American natural gas inventories.

The following significant changes have occurred over the last eight quarters that have influenced the Trust's financial results.

- On October 31, 2006, the Federal Minister of Finance announced a proposal to apply a tax at the trust level on distributions of certain income from publicly traded, specified income flow-through (SIFT) entities at tax rates comparable to the combined federal and provincial corporate tax and to treat such distributions to the unitholders as dividends. The SIFT tax legislation, contained in Bill C-52, *Budget Implementation Act,* 2007, received Royal Assent on June 22, 2007. We are now required to record future income tax related to temporary differences at the Trust level, which represents the difference between the accounting and tax basis of the Trust's net assets. This resulted in the initial recording of a $54.3 million future income tax expense in the second quarter of 2007. In addition, corporate tax rate reductions enacted in the fourth quarter of 2007 resulted in a future income tax recovery of $5.9 million.

- We completed two royalty acquisitions in the third quarter of 2007, for $90.5 million. Both acquisitions were funded through Freehold's credit facilities, which were increased to $210 million. The acquisitions contributed production of 675 boe per day in the fourth quarter of 2007.

- During 2007, the Canadian dollar strengthened considerably relative to the U.S. dollar, which reduced our Canadian dollar price realizations for crude oil.

- In the last half of 2007, WTI crude prices strengthened significantly, reaching record highs in the fourth quarter. This significant rise in benchmark pricing boosted our revenues; however, the revenue increase was mitigated somewhat by the higher Canadian dollar.

- Over the past several quarters, we have experienced higher operating expenses on our working interest properties, which currently comprise about 30% of our total production volumes. Rising costs have been experienced industry wide and particularly in Alberta where strong economic growth and oil sands development have created increased demand for people and services. However, the effect of higher costs on our overall results is mitigated by our large proportion of royalty interest production, which is unencumbered by operating expenses.

- Quarterly fluctuations in the percentage of our total boe production that is derived from royalty interests will result in corresponding fluctuations in operating expenses and third party royalty expenses per boe. Over the past eight quarters, royalty production volumes have varied from 63% to 79% of total boe production.

The accompanying table illustrates the fluctuations experienced over the past eight quarters and the resulting effect on our financial results. Additional information about our quarterly results is provided in our four interim reports for 2007, copies of which are available on SEDAR or on our website.

QUARTERLY REVIEW

	2007				2006			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial ($000s, except as noted)								
Revenue, net of royalty expenses	39,218	36,086	35,907	34,988	31,765	36,550	36,998	33,923
Funds generated from operations	32,591	29,907	30,213	28,297	27,394	31,692	32,565	28,198
Per Trust Unit ($)	0.66	0.61	0.61	0.58	0.56	0.65	0.66	0.58
Distributions to Unitholders	28,096	22,165	22,151	22,133	23,594	26,521	26,502	26,483
Per Trust Unit ($) [1]	0.57	0.45	0.45	0.45	0.48	0.54	0.54	0.54
Net income (loss)	19,067	12,487	(42,533)	9,787	9,545	12,728	14,142	8,766
Per Trust Unit, basic and diluted ($)	0.39	0.25	(0.86)	0.20	0.19	0.26	0.29	0.18
Property and royalty acquisitions	26	90,430	–	–	–	5,382	–	–
Capital expenditures	3,901	1,960	2,830	3,476	3,766	4,649	1,430	1,601
Long-term debt	178,000	179,000	100,000	99,000	100,000	98,000	96,000	105,000
Trust Units outstanding								
Weighted average (000s)	49,282	49,246	49,210	49,175	49,139	49,103	49,068	49,032
At quarter end (000s)	49,317	49,281	49,246	49,210	49,174	49,139	49,103	49,067
Operating ($/boe, except as noted)								
Daily production (boe/d)	8,591	8,219	8,566	8,564	8,313	8,335	8,212	8,794
Royalty interest production (%)	70	69	63	72	79	77	79	76
Average selling price	50.57	48.28	48.21	47.40	41.44	48.95	50.27	43.78
Operating netback	46.47	43.65	42.28	42.06	38.57	44.92	47.08	40.18
Operating expenses	3.14	4.07	3.79	3.33	2.95	2.75	2.43	2.68
Working interest properties	10.56	13.17	10.34	11.82	13.86	11.88	11.51	11.26
General and administrative expenses	2.11	1.35	1.67	3.24	1.44	1.32	1.79	2.69
Benchmark Prices								
WTI crude oil (US$/bbl)	90.68	75.38	65.04	58.16	60.26	70.48	70.70	63.45
Exchange rate (Cdn$/US$)	1.02	0.96	0.91	0.85	0.89	0.89	0.89	0.87
Edmonton Par crude oil (Cdn$/bbl)	86.42	79.95	71.93	67.09	64.48	79.08	78.55	68.96
Light/heavy oil differential (Cdn$/bbl)	29.37	23.95	21.02	16.98	18.80	20.14	17.43	28.57
Bow River Hardisty crude oil (Cdn$/bbl)	57.05	56.00	50.91	50.11	45.69	58.94	61.11	40.39
AECO natural gas (Cdn$/Mcf)	6.00	5.61	7.37	7.45	6.36	6.03	6.27	9.27
Unit Trading Performance								
High ($)	15.85	15.85	15.85	15.30	19.80	23.06	21.70	22.20
Low ($)	14.46	12.51	13.77	13.00	12.43	18.50	18.02	18.44
Close ($)	15.60	15.26	14.53	14.35	14.81	19.00	21.00	19.50
Volume (000s)	7,036	5,172	6,853	6,040	13,867	5,153	5,336	11,155

1. Based on the number of Trust Units issued and outstanding at each record date.

REVENUE

We receive revenue from approximately 250 industry operators. Gross revenue of $152.2 million in 2007 was 6% higher than in 2006, as higher liquids production volumes and higher oil prices offset the slight decline in natural gas prices and volumes. The accompanying table demonstrates the net effect of price and volume variances on gross revenue.

GROSS REVENUE VARIANCES

($000s)	2007 vs. 2006	2006 vs. 2005
Oil and NGL		
Production increase	2,872	7,149
Price increase	7,776	5,844
Net increase	10,648	12,993
Natural gas		
Production increase (decrease)	(1,028)	5,531
Price decrease	(486)	(12,322)
Net decrease	(1,514)	(6,791)
Other revenue decrease	(17)	(49)
Gross revenue increase	9,117	6,153

1. Other revenue includes potash revenue, sulphur revenue, lease rentals, processing fees, and interest income.

Net revenue rose 5% in 2007. Royalty and freehold mineral tax expenses rose 63% in 2007, largely due to a 41% increase in working interest production. Royalty expenses are incurred only on our working interest properties. As well, the Alberta Royalty Credit program was discontinued in 2007.

NET REVENUE

($000s)	2007	2006	2005
Gross revenue	152,184	143,067	136,914
Royalty expenses and freehold mineral taxes [1]	(6,263)	(3,831)	(3,591)
Net revenue	145,921	139,236	133,323

1. Royalty expenses and freehold mineral taxes includes all Crown charges and royalty payments to third parties and are net of the Alberta Royalty Credit in 2006 and 2005.

Production

Our production base is geographically widespread throughout western Canada and in southern Ontario, with the majority of properties located in Alberta. On a boe basis, annual production was 1% higher than last year, as successful development on our working interest properties and royalty acquisitions in the third quarter offset natural production declines. Production from working interest wells increased 41%, while royalty production declined 11%. In 2007, 69% of our production came from royalty interests. On a boe basis, our production profile was 37% heavy oil (averaging 14° API), 36% natural gas, 23% light and medium oil (averaging 36° API), and 4% natural gas liquids (NGL). Production in 2008 is expected to average 8,200 boe per day.

PRODUCTION SUMMARY

(boe/d)	2007	2006	2005
Royalty interest lands	5,825	6,530	5,885
Working interest properties	2,659	1,882	1,751
Total	8,484	8,412	7,636

AVERAGE DAILY PRODUCTION BY PRODUCT TYPE

	2007	2006	2005
Light and medium oil (bbls/d)	1,925	1,678	1,648
Heavy oil (bbls/d)	3,109	3,187	2,840
NGL (bbls/d)	333	358	345
Total oil and NGL (bbls/d)	5,367	5,223	4,833
Natural gas (Mcf/d)	18,703	19,138	16,821
Oil equivalent (boe/d)	8,484	8,412	7,636
Total annual production (Mboe)	3,097	3,070	2,787
Potash (tonnes/d)	14.2	10.5	9.7

PRODUCTION RECONCILIATION

(boe/d)	Royalty Interest Properties	Working Interest Properties	Total Trust
2006 average daily production rate	6,530	1,882	8,412
2006 activities, full year impact	285	486	771
2007 development	75	711	786
2007 acquisitions	225	–	225
Natural decline	(1,290)	(420)	1,710
2007 average daily production rate	5,825	2,659	8,484

Product Prices

WTI crude oil prices averaged US$72.31 per barrel in 2007, up 9% from last year. A stronger Canadian currency during 2007 offset a portion of the economic benefit of higher average oil prices. As a result, average Edmonton Par crude oil prices rose only 5%.

Of particular relevance for Freehold are the markets for heavy oil and prices for the benchmark Bow River Hardisty stream (24.9° API), which is a close proxy for our average oil realizations. The differential between light and heavy oil has a significant impact on our realizations, as approximately 37% of our total boe production is heavy oil.

Natural gas prices tend to be more volatile than oil prices due to supply and demand factors within North America, and this was the case in 2007. Natural gas prices averaged $6.61 per Mcf, 5% lower than 2006. Since the beginning of 2006, natural gas prices have weakened significantly as a warmer than normal winter enabled gas storage levels to build and remain above seasonal levels.

AVERAGE BENCHMARK PRICES [1]

	2007	2006	2005
WTI crude oil (US$/bbl)	72.31	66.22	56.56
Exchange rate (US$/Cdn$)	0.9352	0.8818	0.8260
Edmonton Par crude oil (Cdn$/bbl)	76.35	72.77	68.72
Bow River Hardisty crude oil (Cdn$/bbl)	53.52	51.53	44.83
Light/heavy oil differential (Cdn$/bbl)	22.83	21.23	23.90
AECO natural gas (Cdn$/Mcf)	6.61	6.98	8.48

1. Source for commodity prices: Canadian Association of Petroleum Producers.

Freehold's average selling prices reflect product quality and transportation differences from benchmark prices. On a boe basis, our average price realizations were 6% higher in 2007 due to higher oil prices, partly offset by the decline in natural gas prices and a stronger Canadian dollar compared with last year.

AVERAGE SELLING PRICES

	2007	2006	2005
Oil ($/bbl)	54.38	50.24	46.65
NGL ($/bbl)	53.53	50.29	50.58
Oil and NGL ($/bbl)	54.33	50.25	46.93
Natural gas ($/Mcf)	6.47	6.54	8.55
Oil equivalent ($/boe)	48.63	46.07	48.53
Potash ($/tonne)	225.28	220.13	213.28

Marketing and Hedging

Our royalty lands consist of a large number of properties, with generally small volumes per property. A provision of the leases calls for our natural gas to be marketed with the lessees' production. Historically, we have chosen to market our oil production in the same manner. Some of our leases allow us to take our oil production in kind, and we have chosen to do so to speed up receipt of royalty income. As at December 31, 2007, approximately 40% of our royalty oil production was being marketed by Freehold using 30-day contracts.

We market most of our working interest oil production using 30-day contracts to ensure the highest competitive pricing. Approximately 4% of our natural gas production is sold under marketing arrangements tied to the Alberta monthly or daily spot price (AECO) or other indexed referenced prices.

Our production was unhedged during 2007, and we have no plans to enter into any foreign currency or commodity price hedges at this time. This policy is subject to quarterly review by our board of directors.

EXPENSES

Royalty Expenses and Freehold Mineral Taxes

Oil and gas producers pay royalties to the owners of mineral rights from whom they hold leases. These are paid to the Crown (provincial and federal government) and freehold mineral title owners. Royalty expense includes all Crown charges (including freehold mineral taxes) and royalty payments to third parties. Crown royalty rates are tied to commodity prices and the level of oil and gas sales.

The majority of our freehold mineral taxes, payable annually to the Crown, pertain to two sections of land in the Hayter area that were acquired in the Petrovera acquisition in May 2005. Development activity on these lands has resulted in increased production and higher property values. Prior to the Petrovera acquisition, our freehold mineral taxes were not material and were recorded under working interest expenses.

Royalty expenses rose 63% year over year due to higher freehold mineral taxes, discontinuation of the Alberta Royalty Credit program, and higher working interest production in 2007. As well, royalty expense in 2007 included approximately $250,000 in freehold mineral taxes that related to 2006.

ROYALTY EXPENSES AND FREEHOLD MINERAL TAXES [1]

($000s, except as noted)	2007	2006	2005
Working interest properties			
Crown royalties	4,258	2,697	2,815
Alberta Royalty Credit [2]	–	(361)	(342)
Freehold royalties [3]	745	807	807
Freehold mineral taxes [4]	252	304	283
Total working interest properties	5,255	3,447	3,563
Per boe ($)	5.41	5.02	5.58
Royalty interest lands			
Crown royalties	–	–	–
Freehold royalties [3, 5]	–	–	–
Freehold mineral taxes [4]	1,008	384	28
Total royalty interest lands	1,008	384	28
Per boe ($)	0.47	0.16	0.01
Total royalty expenses and freehold mineral taxes	6,263	3,831	3,591
Per boe ($)	2.02	1.25	1.29
As a percentage of gross revenue	4%	3%	3%

1. Royalty expenses and freehold mineral taxes include all Crown charges and royalty payments to third parties.
2. Effective January 1, 2007, the Alberta Government discontinued the Alberta Royalty Credit.
3. Freehold royalties include mineral title and gross overriding royalty payments to third parties.
4. 2006 and 2005 have been restated to conform to the current presentation. Previously, freehold mineral taxes on our royalty lands were included in working interests properties, as they were not material.
5. We do not incur royalty expenses on production from our royalty interest lands. As the royalty owner, we receive the royalty as income from other companies.

On October 25, 2007, the Government of Alberta announced its "New Royalty Framework" for Crown oil and gas royalty policy. The new royalty regime, which takes effect January 1, 2009, will be a sliding scale formula based on both commodity prices and well productivity. We expect to see little impact on Freehold's current producing wells, given the mature nature of most of our producing assets and the small proportion of our production (about 10%) that is subject to Alberta Crown royalties.

Operating Expenses

Operating expenses are comprised of direct costs incurred and costs allocated among oil, natural gas, and NGL production. Overhead recoveries associated with operated properties are excluded from operating costs and accounted for as a reduction to general and administrative costs. A percentage of operating costs is fixed and, as such, per boe operating costs are highly variable to production volumes. On our working interest properties, which accounted for 31% of our production in 2007, operating expenses per boe of production declined 6%. Over the past two years, the energy sector has experienced cost inflation. The majority of our working interest properties are operated by others, and we expect that the operators will initiate cost reduction measures to manage the impact of inflation. As 69% of our production was from royalties in 2007, we were somewhat sheltered from the effects of increased costs because royalty production is not encumbered by these expenses. Operating costs are forecast to average $3.85 per boe in 2008.

OPERATING EXPENSES

($000s, except as noted)	2007	2006	2005
Working interest properties	11,076	8,309	6,530
Per boe ($)	11.41	12.09	10.22
Royalty interest lands [1]	–	–	–
Per boe ($)	–	–	–
Total operating expenses	11,076	8,309	6,530
Per boe ($)	3.58	2.71	2.34
As a percentage of gross revenue	7%	6%	5%

1. We do not incur operating costs on our royalty interest lands.

General and Administrative Expenses

We have significant land administration, accounting and auditing requirements to administer and collect royalty payments. This includes systems to track lessee activity on the royalty lands. General and administrative (G&A) expenses have remained between 3% and 4% of gross revenue for the past three years.

In 2007, G&A costs totalled $6.6 million, including $4.4 million charged by the Manager for time and direct costs incurred on behalf of the Trust. On a per boe basis, G&A expenses were 15% higher year over year. The rise in G&A costs reflects higher staff levels and general inflationary pressures in Calgary, including a tight employment market that has increased compensation for the Manager's staff. During the year, we expensed $476,000 for the Trust's proportionate share of the Manager's annual bonus plan.

Deferred compensation expenses were also higher in 2007. We recorded a non-cash expense of $265,000 (2006 – $247,000), with a corresponding increase to contributed surplus, as unit based compensation relating to the grant of 17,914 deferred trust units to non-management directors during 2007 (2006 – 12,559 deferred trust units). G&A also included a non-cash charge of $366,000 (2006 – $43,000) for the Trust's proportionate share in 2007 of a long-term incentive compensation plan for employees of the Manager (the Manager's LTIP).

We also continued the work of evaluating internal controls; the anticipated cost of the project is expected to reach $500,000 of which $365,000 has been incurred to date. G&A costs are forecast to average $2.44 per boe in 2008.

GENERAL AND ADMINISTRATIVE EXPENSES

($000s, except as noted)	2007	2006	2005
Gross general and administrative expenses	6,564	5,670	4,479
Less overhead recoveries [1]	(79)	(89)	(87)
Net general and administrative expenses	6,485	5,581	4,392
Per boe ($)	2.09	1.82	1.58
As a percentage of gross revenue	4%	4%	3%

1. Our overhead recoveries are minimal because we do not operate any of our royalty production.

Management Fees

The Manager of the Trust receives a management fee paid in Trust Units.

MANAGEMENT FEES

	2007	2006	2005
Trust Units issued in payment of management fees	142,616	142,616	123,825
Ascribed value ($000s) [1]	2,130	2,649	2,178
Per boe ($)	0.69	0.86	0.78
As a percentage of gross revenue	1%	2%	2%
As a percentage of distributions	2%	3%	3%

1. The ascribed value of the management fees is based on the closing Trust Unit price at the end of each quarter.

Interest Expenses

In the third quarter of 2007, we completed two royalty acquisitions for $90.5 million. The acquisitions were funded through Freehold's credit facilities, which resulted in a 35% increase in interest expense.

NET INTEREST EXPENSE

($000s, except as noted)	2007	2006	2005
Interest on operating line or other	3	10	13
Interest on long-term debt	7,002	5,184	3,145
Net interest expense	7,005	5,194	3,158
Per boe ($)	2.26	1.69	1.13
As a percentage of gross revenue	5%	4%	2%

Depletion and Depreciation and Accretion of Asset Retirement Obligations

Oil and gas properties and royalty interests, including the cost of production equipment, future capital costs associated with proved reserves, and the capitalized portion of asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties payable (see Accounting Policies and Critical Estimates). Reserves are independently evaluated every year as at December 31. For the first three quarters of 2007, the estimate of proved reserves was based on the independent evaluation dated December 31, 2006, adjusted for acquisitions and production. The fourth quarter results were adjusted to reflect the annual reserve evaluation as at December 31, 2007.

Our ceiling test calculation, performed at December 31, 2007, resulted in no impairment loss. The future prices used in estimating cash flows were based on forecasts by an independent reserves evaluator, adjusted for our quality, transportation, and contract differences.

DEPLETION, DEPRECIATION AND ACCRETION EXPENSES

($000s, except as noted)	2007	2006	2005
Depletion and depreciation	72,400	71,874	56,938
Accretion of asset retirement obligations	266	257	252
Total depletion, depreciation and accretion expenses	72,666	72,131	57,190
Per boe ($)	23.47	23.50	20.52
As a percentage of gross revenue	48%	50%	42%

Taxes

Income and Capital Taxes

Freehold Royalty Trust is a taxable trust under the *Income Tax Act* (Canada). We distribute substantially all of our taxable income to Unitholders. By doing so, exposure to current tax at the trust level is eliminated.

Capital taxes consist primarily of the Saskatchewan Capital Tax applied to both taxable capital and gross revenues in that province. Our subsidiary, Freehold Resources Ltd., is a Canadian corporation subject to tax in various jurisdictions. Freehold Resources Ltd. can deduct royalty payments to the Trust in determining its taxable income, and is generally liable for income taxes on its 1% residual interest. Freehold Resources Ltd. is subject to federal and capital tax in any jurisdiction (federal and provincial) in which it has a permanent establishment.

INCOME AND CAPITAL TAXES

($000s)	2007	2006	2005
Provincial capital tax	179	253	120
Current income tax	–	38	985
Total	179	291	1,105

Tax Pools

We are entitled to claim certain tax deductions available to all owners of oil and gas properties. By using two principal deductions - the Canadian Oil and Gas Property Expense and the Resource Allowance - cash distributions in the Trust's initial years were sheltered from income tax. Over time, as a result of a general reduction in tax pools available for future claims, an increasing percentage of the annual distributions become taxable.

On a consolidated basis, the Trust's carrying value for book purposes exceeds the amount available for tax purposes by $278 million.

TAX POOLS

($000s)	2007	2006	2005
Canadian oil and gas property expense	202,164	133,879	144,470
Canadian development expense	13,507	10,852	8,058
Canadian exploration expense	131	–	–
Capital cost allowance	10,708	10,103	7,516
Unit issue costs	4,427	6,641	8,854
Non-capital loss carryovers	–	96	–
Total [1]	230,937	161,571	168,898

1. These amounts, subject to review by Canada Revenue Agency, represent Freehold Royalty Trust's direct tax pools as well as the tax pools of our subsidiary, Freehold Resources Ltd.

The implementation of the SIFT legislation will result in certain of our distributions that would have otherwise been taxed as ordinary income being characterized as dividends in addition to being subject to tax at corporate rates at Freehold's level. Because our property base consisted primarily of royalties, there were few tax pools associated with our assets when the Trust was created in 1996. At year end 2007, we had approximately $230.9 million available in tax pools.

Future Income Taxes

The SIFT tax is not expected to apply to Freehold until 2011 as a transition period applies to trusts that existed prior to November 1, 2006. However, under Canadian GAAP, this enactment of SIFT tax legislation requires the recognition of future income tax. Accordingly, in 2007, Freehold recorded a $47.6 million of future income tax expense with a corresponding increase in future income tax liability.

The future income tax liability on our Consolidated Balance Sheet as at December 31, 2007, represents the net difference between tax values and accounting values (referred to as temporary differences) effected at substantively enacted tax rates expected to apply when the differences reverse.

Currently, the SIFT rules provide that the SIFT tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5% in 2011) plus the provincial SIFT tax factor (which is set at a fixed rate of 13%), for a combined SIFT tax rate of 29.5% in 2011.

On February 26, 2008, the Minister of Finance announced a proposal to base the provincial component of the SIFT tax on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment instead of basing the provincial component of the SIFT tax on a flat rate of 13%. For purposes of calculating the provincial component of the tax, the general corporate taxable income allocation formula will be used. Specifically, the Trust's taxable distributions will be allocated to provinces by taking half of the aggregate of:

- that proportion of the Trust's taxable distributions for the year that the Trust's wages and salaries in the province are of its total wages and salaries in Canada; and
- that proportion of the Trust's taxable distributions for the year that the Trust's gross revenues in the province are of its total gross revenues in Canada.

Under this proposal, the Trust would be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10%. Taxable distributions that are not allocated to any province would instead be subject to a 10% rate constituting the provincial component. There can be no assurance, however, that this proposal will be enacted as proposed.

NETBACKS

Netbacks, calculated on a boe basis, represent the cash margin on the sale of oil and gas. Operating netback is calculated by subtracting royalty expenses and operating costs from revenues.

OPERATING NETBACK

($ per boe)	2007	2006	2005
Royalty interest lands	47.49	45.81	50.01
Working interest properties	34.90	31.64	30.30
Total Trust	43.54	42.64	45.49

On the majority of our production, we receive royalty income from gross production revenue (revenue before any royalty expenses and operating costs are deducted). We do not incur development expenditures, operating expenses, abandonment, or site restoration expenses on our royalty production. The accompanying netback analysis demonstrates the positive effect of this royalty advantage on our cash margins.

2007 NETBACK ANALYSIS

($ per boe)	Royalty Interest Properties	Working Interest Properties	Total Trust
Gross revenue [1]	47.96	51.72	49.14
Royalty expenses and freehold mineral taxes	(0.47)	(5.41)	(2.02)
Net revenue	47.49	46.31	47.12
Operating expenses	–	(11.41)	(3.58)
Operating netback	47.49	34.90	43.54
General and administrative expenses, less non-cash unit based compensation	(2.05)	(1.55)	(1.89)
Interest expense	(3.01)	(0.62)	(2.26)
Income and capital taxes	–	(0.18)	(0.06)
Expenditures on reclamation	–	(0.82)	(0.26)
Funds generated from operations	42.43	31.73	39.07
Reclamation fund withdrawal	–	0.34	0.11
Development expenditures	–	(12.54)	(3.93)
Changes in debt	35.20	3.26	25.19
Net acquisition cost	(42.55)	–	(29.21)
Changes in working capital	(0.70)	(0.70)	(0.70)
Investor netback [2]	34.38	22.09	30.53

1. Includes potash revenue, sulphur revenue and other.
2. Excludes management fee paid in Trust Units,

DISTRIBUTIONS

Distributions declared in 2007 totalled $1.92 per Trust Unit.

2007 DISTRIBUTIONS DECLARED

Record Date	Payment Date	Distribution ($ per Trust Unit)
January 31, 2007	February 15, 2007	0.15
February 28, 2007	March 15, 2007	0.15
March 31, 2007	April 15, 2007	0.15
April 30, 2007	May 15, 2007	0.15
May 31, 2007	June 15, 2007	0.15
June 30, 2007	July 15, 2007	0.15
July 31, 2007	August 15, 2007	0.15
August 31, 2007	September 15, 2007	0.15
September 30, 2007	October 15, 2007	0.15
October 31, 2007	November 15, 2007	0.15
November 30, 2007	December 15, 2007	0.27[1]
December 31, 2007	January 15, 2008	0.15
Total		1.92

1. Includes an additional $0.12 representing increased income in 2007.

From inception to December 31, 2007, we have declared distributions totalling $580.7 million ($16.22) per Trust Unit.

ACCUMULATED DISTRIBUTIONS

Distributions to Unitholders ($000s)	2007	2006	2005
Accumulated, beginning of period	486,124	383,024	298,214
Accumulated, end of period	580,669	486,124	383,024
Distributions per Trust Unit ($) [1]			
Accumulated, beginning of period	14.30	12.20	10.28
Accumulated, end of period	16.22	14.30	12.20

1. Based on the number of Trust Units issued and outstanding at each record date.

Distribution Policy

The regularly monthly distribution is currently fixed at $0.15 per Trust Unit. Our distribution policy takes into consideration forecasted cash provided by operating activities, debt levels, and capital expenditures. We have a declining asset base, and ongoing development activities and acquisitions are necessary to replace production and add additional reserves. The success of these activities, along with commodity prices, are the main factors influencing the sustainability of our distributions.

2008 KEY OPERATING ASSUMPTIONS

	March 14, 2008
Average daily production (boe/d)	8,200
Average WTI oil price (US$/bbl)	85.00
Average Bow River Hardisty oil price (Cdn$/bbl)	60.00
Average AECO natural gas price (Cdn$/Mcf)	6.65
Average light/heavy oil price differential (Cdn$/bbl)	25.00
Average exchange rate (Cdn$/US$)	1.00
Average operating costs ($/boe)	3.85
Average general and administrative costs ($/boe)	2.44
Capital expenditures ($ millions)	10.6
Long-term debt at year end ($ millions)	155
Weighted average Trust Units outstanding (thousands)	49,371
Estimated portion of distributions taxable as income (%)	90-100

Recognizing the cyclical nature of our industry, we caution that significant changes (positive or negative) in commodity prices (including light/heavy oil price differentials), foreign exchange rates, or production rates will result in adjustments to the distribution level. It is also inherently difficult to predict activity levels on our royalty lands since we do not know the future plans of the various operators. Freehold is particularly vulnerable to swings in the light/heavy oil price differential, as approximately 37% of our total boe production is heavy oil. Supply and demand imbalances could keep heavy oil price differentials well above historical averages. We will continue to monitor prices and activity levels closely. Our guidance is reviewed and updated quarterly.

The following table provides an analysis of the potential impact key factors may have on distributions to Unitholders.

SENSITIVITY ANALYSIS

Variables	Change (+/-)	Estimated Change in Distributions to Unitholders ($000s)	Estimated Change in Distributions to Unitholders ($/Trust Unit)
WTI crude oil price	US$1.00/bbl	1,992	0.04
Light/heavy oil price differential	Cdn$1.00/bbl	1,992	0.04
Natural gas price	Cdn$0.25/Mcf	1,612	0.03
Exchange rate (US$/Cdn$)	0.01	1,718	0.03
Interest rates	1%	1,709	0.03
Oil and NGL production	100 bbls/d	2,254	0.05
Natural gas production	1,000 Mcf/d	2,269	0.05

LIQUIDITY AND CAPITAL RESOURCES

Operating Activities

The following table illustrates the relationship between cash provided from operating activities and historical distributions, as well as net income (loss) and historical distributions. Net income includes significant non-cash charges that do not impact cash provided by operating activities. In 2007, these charges amounted to $123.0 million (2006 – $75.0 million.) Net income also includes fluctuations in future income taxes due to changes in tax rates and tax rules, as outlined above. In addition, other non-cash charges (such as depletion and depreciation on property, plant and equipment and accretion on the asset retirement obligations), do not represent the actual cost of maintaining our productive capacity given the natural declines associated with oil and gas assets. In these circumstances, where distributions exceed net income, a portion of the cash distribution paid to Unitholders may represent an economic return on the Unitholders' capital.

DISTRIBUTION ANALYSIS

($000s, except as noted)	2007	2006	2005
Cash provided by operating activities	119,641	130,835	96,925
Net income (loss)	(1,192)	45,181	58,346
Cash distributions paid or payable	94,545	103,100	84,810
Excess of cash provided by operating activities over cash distributions	27%	27%	14%
Shortfall of net income over cash distributions	-101%	-56%	-31%

Financing Activities

In conjunction with acquisitions completed in the third quarter of 2007, we expanded our credit facilities from $165 million to $210 million. These credit facilities were used to fund $78 million of the $90.5 million purchase price of the acquisitions, inclusive of transaction costs. At December 31, 2007, we had no short-term debt outstanding and long-term debt was $178 million. We had positive working capital of $11.2 million, resulting in net debt of $166.8 million. In addition, we had accrued $1.1 million as a long-term liability relating to incentive compensation pursuant to the Manager's LTIP (see General and Administrative Expenses). We currently have $32 million of available capacity under our credit facilities.

DEBT ANALYSIS

($000s)	2007	2006	2005
Long-term debt	178,000	100,000	107,000
Short-term debt (operating line)	–	–	–
Total debt	178,000	100,000	107,000
Less: working capital	11,219	9,050	16,281
Net debt obligations	166,781	90,950	90,719

At December 31, 2007, our ratio of net debt (total debt less positive working capital) to trailing funds generated from operations was 1.4 to 1. In keeping with our conservative approach to debt management, we anticipate that excess cash will be directed to debt repayment.

FINANCIAL LEVERAGE AND COVERAGE RATIOS [1]

	2007	2006	2005
Net debt to trailing funds generated from operations (times)	1.4	0.8	0.8
Net debt to distributions (times)	1.8	0.9	1.1
Distributions to interest expense (times)	13.5	19.8	26.9
Net debt to net debt plus equity (%)	40	21	19

1. Funds generated from operations, distributions, and interest expense are 12-months trailing.

The following table illustrates the changes in working capital at the end of each quarter during 2007. In the oil and gas industry, accounts receivable from industry partners are typically settled in the following month. However, due to administrative issues, payments to freehold and gross overriding royalty owners are often delayed longer. Therefore, working capital can fluctuate significantly resulting from volume and prices changes relative to each period end.

COMPONENTS OF WORKING CAPITAL [1]

($000s)	Dec. 31 2007	Sept. 30 2007	June 30 2007	Mar. 31 2007	Dec. 31 2006
Cash	393	82	254	677	421
Accounts receivable	26,802	26,883	25,865	27,870	29,850
Current assets	27,195	26,965	26,119	28,547	30,271
Distributions payable to Unitholders	(7,398)	(7,392)	(7,387)	(7,381)	(7,376)
Accounts payable and accrued liabilities	(8,578)	(7,891)	(7,491)	(10,124)	(13,845)
Current liabilities	(15,976)	(15,283)	(14,878)	(17,505)	(21,221)
Working capital [1]	11,219	11,682	11,241	11,042	9,050

1. Working capital is comprised of current assets minus current liabilities.

Trust Units Outstanding

As at March 14, 2008, there were 49,316,813 Trust Units outstanding, unchanged from December 31, 2007.

At the Annual and Special Meeting of Unitholders held on May 10, 2006, Unitholders approved a deferred trust unit plan for non-management directors whereby fully vested deferred trust units are granted annually. Under this plan, distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of distribution. As at December 31, 2007, there were 30,473 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement.

On January 1, 2008, the Board approved annual grants for 2008 totalling 11,538 deferred trust units, allocating 1,923 to each eligible director and 3,846 to the Chair of the Board. As at March 14, 2008, there were 42,722 deferred trust units outstanding.

TRUST UNITS OUTSTANDING

	2007	2006	2005
Weighted average			
Basic	49,228,411	49,085,795	42,812,470
Diluted	49,228,411	49,093,609	42,812,470
At December 31	49,316,813	49,174,197	49,031,581

New SIFT Tax Legislation

The new SIFT tax is expected to result in adverse tax consequences to Freehold and certain Unitholders (including Unitholders that are tax deferred or non-residents of Canada) and may impact Freehold's cash distributions starting in 2011. The after tax impact for Canadian resident individuals who hold Freehold Trust Units outside a tax deferred plan is mitigated by the federal and provincial enhanced dividend tax credit mechanism that will apply in 2011 and future years.

The SIFT tax may reduce the value of our Trust Units, which would be expected to increase our cost of raising capital in the public capital markets. In addition, the tax changes are expected to substantially eliminate the competitive advantage that Freehold and other Canadian trusts enjoy relative to their corporate peers in raising capital in a tax-efficient manner and place Freehold and other Canadian trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity level taxation.

The tax changes are also expected to make our Trust Units less attractive as an acquisition currency. As a result, it may become more difficult for Freehold to compete effectively for acquisition opportunities. There can be no assurance that we will be able to reorganize Freehold's legal and tax structure to substantially mitigate the expected impact of the tax changes.

Further, the tax changes provide that, while there is no intention to prevent "normal growth" during the transitional period, any "undue expansion" could result in the transition period being "revisited", presumably with the loss of the benefit to us of that transitional period. As a result, the adverse tax consequences resulting from the tax changes could be realized sooner than January 1, 2011. On December 15, 2006, the Department of Finance issued guidelines with respect to what is meant by normal growth in this context. "Normal growth" would include equity growth within certain "safe harbour" limits, measured by reference to market capitalization as of the end of trading on October 31, 2006. Those safe harbour limits are 40% for the period from November 1, 2006 to December 31, 2007, and 20% in each of the following three years. Moreover, the yearly limits are cumulative, so that any unused limit for a period carries over into the subsequent period.

Our market capitalization as of the close of trading on October 31, 2006 was approximately $928.7 million, which means our safe harbour equity growth amount for the period ending December 31, 2007 is approximately $371.5 million, and for each of calendar 2008, 2009 and 2010 is an additional $185.7 million with an ultimate total equity growth amount of no more than $928.7 million. We have not issued any equity since the SIFT tax announcement in 2006.

While these guidelines are such that it is unlikely they would affect our ability to raise the capital required to maintain and grow our existing operations in the ordinary course during the transitional period, they could adversely affect the cost of raising capital and our ability to undertake significant acquisitions.

Investing Activities

Acquisitions

Our strategy is to acquire appropriate assets, with a bias toward royalty interests, to provide long-term growth in the value of the Trust. The key acquisition criteria are:

- **Quality Assets:** producing properties with an established production history and low reserve risk;
- **Attractive Returns:** a forecast internal rate of return that is 400 basis points above long-term (ten year) Government of Canada bonds;
- **Reasonable Assumptions:** commodity price and exchange rate assumptions from an independent engineering firm acceptable to the board of directors;
- **High Operating Netbacks;** and
- **Long Economic Life:** an expected economic life of not less than ten years.

On August 31, 2007, we acquired gross overriding royalty (GORR) interests on 309,800 gross acres of land in Alberta and Saskatchewan for $57.6 million. On September 5, 2007, we acquired a 7% GORR on 9,078 gross acres of land at Dixonville, Alberta, for $32.8 million. Both acquisitions were funded through Freehold's credit facilities. We continue to pursue opportunities to augment our production and reserves, primarily targeting royalty interests, while maintaining a disciplined valuation approach to ensure that any acquisition we complete will be accretive to our present and future Unitholders.

PROPERTY AND ROYALTY ACQUISITIONS

($000s)	2007	2006	2005
Purchase price	93,700	5,500	353,713
Acquisition fee [1]	–	–	5,306
Interest expense	1,745	–	5,349
Evaluation and legal costs	405	–	2,303
Purchase price adjustments [2]	(5,394)	(118)	(14,966)
Additions to petroleum and natural gas interests	90,456	5,382	351,705
Working capital	–	–	–
Net acquisition costs	90,456	5,382	351,705

1. The 1.5% acquisition fee payable to the Manager for acquisitions completed on behalf of the Trust was eliminated effective January 1, 2006
2. Net revenue from effective date to closing.

Capital Expenditures

Our capital expenditure obligations (with respect to our working interest properties) are deducted from funds generated from operations prior to the determination of distributions to Unitholders. The amount of expenditures to be deducted is limited to 15% of annual funds generated from operations. As we do not incur development expenditures on our royalty lands, our capital requirements are modest, relative to most energy trusts. In 2007, development expenditures of $12.2 million amounted to 10% of funds generated from operations.

For 2008, we have approved a development budget of $10.6 million with respect to our working interest properties. We expect to fund distributions and capital expenditures from cash provided by operating activities. However, we will continue to fund acquisitions and growth through additional debt and equity. In the oil and gas sector, because of the nature of reserve reporting, natural reservoir declines, and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Therefore maintenance capital is not disclosed separately from development capital spending.

CAPITAL EXPENDITURES

($000s)	2007	2006	2005
Development drilling	8,526	7,584	5,379
Plant and facilities	3,641	3,862	2,603
Total capital expenditures	12,167	11,446	7,982
As a percentage of funds generated from operations	10.0%	9.6%	6.8%

Reclamation Fund

We are liable for our share of ongoing environmental obligations and the ultimate reclamation of our working interest properties upon abandonment. We have no reclamation responsibilities on our royalty assets as these are the responsibility of the working interest owners. Ongoing environmental obligations are funded from funds generated from operations. At December 31, 2007, our estimated undiscounted share of future environmental and reclamation obligations for the working interest properties is approximately $23.6 million.

In 1996, we established a reclamation fund to ensure that required funds are available for future reclamation of working interest wells and facilities once they have reached the end of their economic lives. The fund consists of cash invested in an interest-bearing account and is funded by quarterly cash payments. We contributed $470,000 in cash and interest to the fund during 2007 and withdrew $799,000, which was spent on reclamation activities. At December 31, 2007, the fund had a balance of $1.8 million. For 2008, quarterly contributions have increased from $100,000 to $150,000 to ensure that future obligations can be met.

RECLAMATION FUND SUMMARY

($000s)	Cumulative Since Inception	2007	2006	2005
Reclamation fund, beginning balance	–	2,117	1,964	1,646
Reclamation fund contributions	3,452	470	455	422
Expenditures on reclamation	(1,664)	(799)	(302)	(104)
Reclamation fund, ending balance	1,788	1,788	2,117	1,964

UNITHOLDER TAXATION

For purposes of the *Income Tax Act* (Canada), Freehold Royalty Trust is treated as a mutual fund trust. Each year, we file a T3 income tax return with the taxable income allocated to and made taxable in the hands of Unitholders. This taxable income is allocated, on T3 supplementary forms, to each Unitholder who was entitled to distributions for the year. The T3 slip will report the taxable portion of the distribution in Box 26 and the return of capital portion in Box 42. Unitholders reduce the adjusted cost base (ACB) of their Trust Units by an amount equal to the portion of the distribution received in the form of return of capital.

Canadian Residents

For Canadian tax purposes, 91% of distributions declared in 2007 were taxable as income, unless held in a registered plan, such as a Registered Retirement Savings Plan, a Registered Retirement Income Fund, a Deferred Profit Sharing Plan or a Registered Education Savings Plan. For 2008, we currently estimate that 90-100% of distributions to Unitholders will be taxable as other income.

Non-Residents of Canada

Unitholders who are not residents of Canada for income tax purposes are encouraged to seek advice from a qualified tax advisor in their country of residence for the tax treatment of distributions. Distributions paid or payable to non-residents of Canada are subject to a withholding tax of 25% as prescribed by the *Income Tax Act* (Canada). This withholding tax may be reduced in accordance with reciprocal tax treaties. In the case of the Tax Treaty between Canada and the U.S., the withholding tax for U.S. residents is 15%.

United States Residents

For Trust Units held outside a qualified retirement plan, 100% of the distributions should be reported as ordinary dividends unless the Unitholder elects to treat Freehold as a Qualified Electing Fund (QEF), in which case the Unitholder's share of income should be reported as ordinary income. In consultation with our U.S. tax advisors, we believe that Freehold should be classified as a passive foreign investment company (PFIC) under U.S. federal income tax principles. As such, distributions made during 2007 are subject to the provisions of U.S. federal income taxation applicable to a PFIC. To allow Unitholders the ability to make a QEF election, we post annually a PFIC Annual Information Statement on our website. Unitholders should contact their own tax advisors for information on correctly completing Form 8621. This information is not available from Freehold.

Additional income tax information for Unitholders is available on our website.

BUSINESS RISKS AND MITIGATING STRATEGIES

The operations of an energy trust are subject to the same industry risks and conditions faced by conventional oil and gas companies. The most significant of these include:

- Fluctuations in commodity prices and quality differentials as a result of weather patterns, world and North American market forces or shifts in the balance between supply and demand for crude oil and natural gas;
- Variations in currency exchange rates;
- Imprecision of reserve estimates and uncertainty of depletion and recoverability of reserves. Our reserves will deplete over time through continued production and we and our lessees may not be able to replace these reserves on an economic basis;

- Industry activity levels and intense competition for land, goods and services and qualified personnel;
- Stock market volatility and the ability to access sufficient capital from internal and external sources;
- Operational or marketing risks resulting in delivery interruptions, delays or unanticipated production declines;
- Changes in government regulations, taxation, and royalties; and
- Safety and environmental risks.

As a royalty trust, we are also subject to the following risks:

- Fifteen royalty payors account for about two-thirds of our royalty income, and changes to their businesses may have a significant effect on our results.
- Higher prime borrowing rates, which may increase interest expense on our debt, and which may make fixed income investments more attractive to investors of Trust Units.

We employ the following strategies to mitigate these risks:

- Our diversified revenue stream limits the size of any one property with respect to our total assets.
- We are not liable for abandonment and reclamation costs on our royalty lands.
- Due to our high percentage of royalty lands, we have one of the lowest all-in cost structures of our peer group. In addition, we maintain a focus on controlling direct costs to maximize profitability.
- We maintain an aggressive auditing program to ensure that we are paid royalties on our production from our lands in accordance with the prices obtained by the royalty payor and that unwarranted or excessive deductions are not being taken. During 2007, our audit staff issued audit exception queries amounting to $5.8 million, bringing the total amount of audit exception queries since 1997 to $28.1 million, $21.3 million of which we have successfully recovered.
- We adhere to strict investment criteria for acquisitions, seeking royalty and working interest properties that have high netbacks, long reserve life, low risk development potential, and product diversification.
- We market our products to a diverse range of buyers. Currently, we do not have any commodity price, exchange rate, or interest rate hedging programs in place and do not anticipate a change in this policy.
- We employ a qualified team of oil and gas professionals with many years of experience and knowledge in managing our assets.
- We maintain levels of liability insurance that meet or exceed industry standards.
- We employ a conservative approach to debt management. As circumstances warrant, we allocate a portion of funds generated from operations to debt repayment.

Environmental Regulation and Risk

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation under a variety of federal, provincial, and local laws and regulations. Compliance with these regulations can require significant expenditures and a breach may result in fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability, and potentially increased capital expenditures and operating costs.

In 2002, the Government of Canada ratified the Kyoto Protocol, which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate about Canada's ability to meet these targets and the Government's strategy or alternative strategies on climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases, whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Trust.

On March 8, 2007, the Alberta Government introduced Bill 3, the Climate Change and Emissions Management Amendment Act, which intends to reduce greenhouse gas emission intensity from large industries. Bill 3 states that facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12% starting July 1, 2007; if such reduction is not initially possible the companies owning the large emitting facilities will be required to pay $15 per tonne for every tonne above the 12% target. These payments will be deposited into an Alberta-based technology fund that will be used to develop infrastructure to reduce emissions or to support research into innovative climate change solutions. Alternatively, large emitters can invest in projects outside of their operations that reduce or offset emissions on their behalf provided that these projects are based in Alberta. Prior to investing, the offset reductions offered by a prospective operation must be verified by a third party to ensure that the emission reductions are real. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on the Trust and its operations and financial condition.

On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution, also known as ecoAction, which includes the Regulatory Framework for Air Emissions. The plan covers not only large industry, but also regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products. Regarding large industry and industry related projects, ecoAction is intended to achieve the following: (i) an absolute reduction of 150 megatonnes in greenhouse gas emissions by 2020 by imposing mandatory targets; and (ii) a 50% reduction in air pollution from industry by 2015 by setting certain targets. New facilities using cleaner fuels and technologies will have a grace period of three years. To facilitate compliance with the plan's requirements, while at the same time allowing companies to be cost-effective, innovative and adopt cleaner technologies, certain options are provided. These are: (i) inhouse reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

On January 24, 2008, the Alberta Government announced its plan to reduce projected emissions in the province by 50% by the year 2050. This will result in real reductions of 14% below 2005 levels. The Alberta Government stated it will form a government-industry council to determine a go-forward plan for implementing technologies that will significantly reduce greenhouse gas emissions by capturing air emissions from industrial sources and locking them permanently underground in deep rock formations (carbon capture). In addition, the plan calls for energy conservation by individuals, increased investment in clean energy technologies, and incentives for expanding the use of renewable and alternative energy sources such as bioenergy, wind, solar, hydrogen, and geothermal. Initiatives under this theme will account for 18% of Alberta's reductions. A detailed implementation plan is to be developed and released in the spring of 2008.

INDUSTRY TRENDS

Industry wide, 18,606 wells were drilled in western Canada during 2007, down 19% from 2006. The Petroleum Services Association of Canada predicts that activity will decline further in 2008, to about 14,425 wells. The decline is in response to weak natural gas markets experienced in 2007, high operating costs, and the strength of the Canadian dollar. As well, the new Alberta Crown royalty structure that takes effect next year could significantly change the economics of future exploration and development activities in the province. A number of large exploration and production companies have announced reduced capital spending plans and scaled back drilling programs, especially in gas-prone areas of Alberta. Most of Freehold's gas-prone lands are located in southeastern Alberta and southwestern Saskatchewan, where productivity per well is low, relative to other areas of the Western Canada Sedimentary Basin. In these areas, natural gas pricing has the most influence on producers' drilling decisions. A dramatic reduction in industry drilling would likely be reflected on our royalty lands, but it is not possible to predict what the impact might be on Freehold's future production and reserves.

We view continuing development on our royalty lands as an essential part of our future success. On an equivalent net basis, a total of 25.9 wells were drilled on Freehold's lands in 2007, down slightly from 2006 when 26.2 equivalent net wells were drilled. Of note, there were 92 (4.1 equivalent net) licensed drilling locations on our royalty lands at year-end 2007, compared with 119 (6.1 equivalent net) locations at the end of 2006.

Continued geopolitical uncertainty and strong global demand growth are expected to keep crude oil prices high, while storage levels and weather will be the key demand factors for natural gas prices. Bitumen production from Alberta's oil sands is expected to increase significantly over the next several years. The growing surplus of heavy crude and current lack of upgrading capacity may have a significant negative impact on our price realizations due to our heavier product mix. Supply and demand imbalances could result in the heavy oil price differential remaining well above historical averages.

CONTROLS AND ACCOUNTING MATTERS

In compliance with Multilateral Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, Freehold has filed certificates signed by our Chief Executive Officer (CEO) and Chief Financial Officer (CFO) that, among other things, deal with the matter of disclosure controls and procedures and internal control over financial reporting.

While we believe that the disclosure controls and procedures provide a reasonable level of assurance that they are effective, we do not expect that the disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

Disclosure Controls

Disclosure controls and procedures are controls and other procedures that are designed to provide reasonable assurance that information required to be disclosed in regulatory filings is recorded, processed, summarized, and reported within the periods specified. They include controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

Management has evaluated the effectiveness of the Trust's disclosure controls and procedures as of March 14, 2008. This evaluation was performed under the supervision of, and with the participation of the CEO and the CFO. It took into consideration Freehold's Disclosure, Insider Trading, Code of Business Conduct and Conflict of Interest, and Whistleblower policies, as well as the functioning of the Manager, the officers, the board of directors, and board committees. In addition, the evaluation covered the processes, systems and capabilities relating to regulatory filings, public disclosures, and the

identification and communication of material information. Based on this evaluation, management has concluded that Freehold's disclosure controls are effective in ensuring that material information relating to the Trust is made known to management on a timely basis.

Internal Control Over Financial Reporting

Internal control over financial reporting is a process designed to provide reasonable assurance about the reliability of financial reporting and the preparation of financial statements in accordance with GAAP. The process includes policies and procedures:

- to maintain records that accurately and fairly reflect transactions and dispositions of assets,
- to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements and that receipts and expenditures are being made with proper authorization, and
- to provide reasonable assurance regarding prevention or timely detection of unauthorized transactions that could have a material effect on the financial statements.

Management has evaluated the design of internal controls over financial reporting and has concluded that design is adequate.

Proposed revisions to Multilateral Instrument 52-109 were published for public comment on March 30, 2007. On November 23, 2007, the Canadian Securities Administrators (CSA) issued CSA Notice 52-319 advising that, as a result of the comments received, they plan to make significant revisions and will publish an amended version of the proposed materials for comment. The effective date is not yet known. However, in preparation for certification under the proposed Instrument as early as December 31, 2008, we have been actively engaged with our external auditors and financial advisors to develop and implement the activities necessary to meet the expected certification requirements. The revised Instrument is expected to require the CEO and CFO to certify in annual certificates that they have evaluated the operating effectiveness of internal control over financial reporting as of the end of the financial year. We will be required to disclose in our annual MD&A a description of the process used for evaluating the effectiveness of internal control over financial reporting and our conclusions about the effectiveness of internal control over financial reporting as of the end of the financial year.

Changes in Accounting Policies, Including Initial Adoption, and New Accounting Standards

On January 1, 2007, the Trust adopted the new Canadian accounting standards for financial instruments - recognition and measurement, hedging and comprehensive income. The new standards require all financial instruments within their scope, including all derivatives, to be recognized on the balance sheet initially at fair value. Subsequent measurement of all financial assets and liabilities except those held-for-trading and available-for-sale are measured at amortized cost determined using the effective interest rate method. Held-for-trading financial assets are measured at fair value with changes in fair value recognized in earnings. Available-for-sale financial assets are measured at fair value with changes in fair value recognized in comprehensive income and reclassified to earnings when derecognized or impaired.

Cash and short-term investments, if any, are held-for-trading investments, and the fair values approximate their carrying value due to their short-term nature. Accounts receivable are classified as loans and receivables and accounts payable and accrued liabilities are classified as other financial liabilities and the fair values approximate their carrying value due to the short-term nature of these instruments. The Trust has not designated any financial instruments as available-for-sale or held-to-maturity.

The Trust did not identify any material embedded derivatives that required separate recognition and measurement.

New Canadian accounting standards have been issued that will require additional disclosure in the Trust's financial statements commencing January 1, 2008. Canada's Accounting Standards Board (AcSB) has issued CICA Handbook Section 3862 and 3863, Financial Instruments - Disclosures, and Financial Instruments - Presentation. The AcSB has issued CICA Handbook Section 1535, Capital Disclosures, which requires entities to disclose their objectives, policies and processes for managing capital and whether they are in compliance with any externally imposed capital requirements. These standards will be effective for the Trust commencing January 1, 2008. We are in the process of evaluating the effects these standards will have on our financial statement preparation.

In 2006, the AcSB ratified a strategic plan that will result in the convergence of Canadian GAAP, as used by public companies, with International Financial Reporting Standards (IFRS) over a transitional period. The AcSB has developed and published a detailed implementation plan, with a changeover date for fiscal years beginning on or after January 1, 2011. This initiative is in the early stages and we are reviewing the plan to assess the potential impact the changeover to IFRS will have on our financial statement preparation.

Accounting Policies and Critical Estimates

Our financial statements are prepared within a framework of GAAP selected by management and approved by our board of directors.

The assets, liabilities, revenues and expenses reported in our financial statements depend to varying degrees on estimates made by management. These estimates are based on historical experience and reflect certain assumptions about the future that are believed to be both reasonable and conservative. The more significant reporting areas are crude oil and natural gas reserve estimation, depletion, impairment of assets, oil and gas revenue accruals, asset retirement obligations, and future income taxes. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known.

An estimate is considered a critical accounting estimate if it requires management to make assumptions about matters that are highly uncertain, and if different estimates that could have been used would have a material impact. We continually evaluate the estimates and assumptions. In the normal course, changes are made to assumptions underlying all critical accounting estimates to reflect current economic conditions and updating of historical information used to develop the assumptions. Except as discussed in this MD&A, we are not aware of trends, commitments, events, or uncertainties that are expected to materially affect the methodology or assumptions associated with the critical accounting estimates.

RESERVE ESTIMATES, DEPLETION AND CEILING TEST

The current estimates of oil and gas reserves and our future capital expenditures are based on an independent evaluation conducted as of December 31, 2007. Reserve estimates are updated once a year (as at December 31) and when a significant acquisition is completed. The reserve and recovery information provided are only estimates. The actual production and ultimate reserves may be greater than or less than the estimates and the differences may be material.

We follow the full cost method of accounting for petroleum and natural gas interests. Oil and gas properties and royalty interests, including the costs of production equipment and future capital costs associated with proved reserves and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. An increase in estimated proved oil and gas reserves would result in a corresponding reduction in the depletion rate. As at December 31, 2007, the depletion calculation included $0.6 million for estimated future development costs associated with proved undeveloped reserves and excluded $30.3 million for the lower of cost and estimated value of unproved lands.

Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties. The ceiling test estimates were reviewed at year-end to ensure that they are reasonable and supportable in light of current economic conditions. The ceiling test, performed as at December 31, 2007, indicated that the undiscounted future net revenues from proved reserves exceed the net book value of the properties. Accordingly, no write down of oil and gas properties was required.

ACCRUALS

Freehold follows the accrual method of accounting, making estimates in its financial and operating results. This may include estimates of revenues, royalties, production and other expenses and capital items related to the period being reported, for which actual results have not yet been received. We expect that these accrual estimates will be revised, upwards or downwards, based on the receipt of actual results.

We have no operational control over our royalty lands, and we primarily hold small interests in several thousand wells. Thus, obtaining timely production data from the well operators is extremely difficult. As a result, we use government reporting databases and past production receipts to estimate revenue accruals.

ASSET RETIREMENT OBLIGATIONS

Accounting standards require us to recognize the fair value of an asset retirement obligation in the period in which it is incurred and when a reasonable estimate of the fair value can be made. The fair value of the estimated asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on the unit-of-production method over the life of the reserves. Once the initial asset retirement obligation is measured, it must be adjusted at the end of each period to reflect the passage of time as well as changes in the estimated future cash flows that underlie the obligation.

We have no asset retirement obligations on our royalty income properties. Our asset retirement obligations result from the responsibility to abandon and reclaim our net share of all working interest properties. The net present value of our total asset retirement obligation is estimated to be $6.6 million (discounted at a weighted average credit adjusted risk free rate of 5.8%), with the undiscounted value being $23.6 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being more than 15 years away.

In determining our asset retirement obligations, we are required to make a significant number of estimates with respect to activities that will occur in many years to come. In arriving at the recorded amount of the asset retirement obligation numerous assumptions are made with respect to ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligation also results in an increase to the carrying cost of capital assets. The obligation accretes to a higher amount with the passage of time as it is determined using discounted present values. A change in any one of the assumptions could affect the estimated future obligation and in return, net income. It is difficult to determine the impact of a change in any one of our assumptions. As a result, a reasonable sensitivity analysis cannot be performed.

FUTURE INCOME TAXES

We follow the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. The actual amount of future income tax may be greater than or less than the estimates and the differences may be material.

UNIT BASED COMPENSATION

A deferred trust unit plan was established in 2006 for the non-management directors of Freehold whereby fully vested deferred trust units are granted annually. Under this plan, distributions to Unitholders declared prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of distribution. Compensation expense is recognized at market value at the time of grant or distribution with a corresponding increase to contributed surplus. Upon redemption of the deferred trust units for Trust Units, the amount previously recognized in contributed surplus is recorded as an increase to Unitholders' capital (see Trust Units Outstanding and General and Administrative Expenses).

Effective January 1, 2006, we began funding a portion of the costs of the Manager's LTIP. The Manager's LTIP uses a combination of the value of phantom Rife shares and Trust Units as the basis for rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. As participants in the Manager's LTIP receive a cash payment on a fixed vesting date, compensation expense is determined based on the intrinsic value of the rights at each period end. The valuation incorporates the period end Trust Unit price, the number of rights outstanding at each period end, and certain management assumptions. Compensation expense is recognized over the vesting period with a corresponding increase or decrease in liabilities. The Trust has not incorporated an estimated forfeiture rate for rights that will not vest; rather, the Trust accounts for actual forfeitures as they occur (see General and Administrative Expenses).

management's report

Management has prepared the accompanying consolidated financial statements of Freehold Royalty Trust in accordance with Canadian generally accepted accounting principles.

Management is responsible for the accuracy and integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded, transactions are properly authorized and reliable accounting records are produced for financial reporting purposes.

External auditors, KPMG LLP, were appointed by the Unitholders to perform an examination of the corporate and accounting records so as to express an opinion on the consolidated financial statements of Freehold Royalty Trust. Their examination included tests and procedures considered necessary to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The board of directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. It exercises its responsibilities primarily through the audit committee, all of whose members are independent directors of Freehold Resources Ltd. The committee meets with management and the independent auditors to ensure that management's responsibilities are properly discharged.

DAVID J. SANDMEYER
President and Chief Executive Officer

JOSEPH N. HOLOWISKY
Vice President, Finance and Administration and
Chief Financial Officer

February 27, 2008

auditor's report

TO THE UNITHOLDERS OF FREEHOLD ROYALTY TRUST

We have audited the consolidated balance sheets of Freehold Royalty Trust as at December 31, 2007 and 2006 and the consolidated statements of income and deficit and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2007 and 2006, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP
CHARTERED ACCOUNTANTS
Calgary, Canada

February 27, 2008

consolidated balance sheets

($000s)	December 31 2007	2006
Assets		
Current assets:		
Cash	$ 393	$ 421
Accounts receivable	26,802	29,850
	27,195	30,271
Reclamation fund (note 6)	1,788	2,117
Deferred long-term compensation (note 8)	697	86
Petroleum and natural gas interests (note 3)	474,520	441,754
	$ 504,200	$ 474,228
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	$ 7,398	$ 7,376
Accounts payable and accrued liabilities	8,578	13,845
	15,976	21,221
Asset retirement obligation (note 6)	6,608	4,598
Unit based compensation payable (note 8)	1,106	129
Long-term debt (note 5)	178,000	100,000
Future income tax liability (note 10)	51,404	3,832
Unitholders' equity:		
Unitholders' capital (note 7)	564,828	562,698
Contributed surplus (note 8)	512	247
Deficit	(314,234)	(218,497)
	251,106	344,448
	$ 504,200	$ 474,228

See accompanying notes to consolidated financial statements.

Approved on behalf of Freehold Royalty Trust by Freehold Resources Ltd. as Administrator:

WILLIAM W. SIEBENS
Director

D. NOLAN BLADES
Director

consolidated statements of income (loss) and deficit and comprehensive income (loss)

($000s, except per unit and weighted average data)	Year Ended December 31 2007	2006
Revenue:		
Royalty income and working interest sales	$ 152,184	$ 143,067
Royalty expense and freehold mineral tax	(6,263)	(3,831)
	145,921	139,236
Expenses:		
Operating	11,076	8,309
General and administrative	6,485	5,581
Interest on long-term debt	7,005	5,194
Depletion and depreciation	72,400	71,874
Accretion of asset retirement obligation (note 6)	266	257
Management fee (note 9)	2,130	2,649
	99,362	93,864
Net income before taxes	46,559	45,372
Income and capital taxes (note 10)	179	291
Future income tax expense (reduction) (note 10)	47,572	(100)
	47,751	191
Net income (loss) and comprehensive income (loss)	(1,192)	45,181
Deficit, beginning of year	(218,497)	(160,578)
Distributions declared	(94,545)	(103,100)
Deficit, end of year	$ (314,234)	$ (218,497)
Net income (loss) per Trust Unit, basic and diluted	$ (0.02)	$ 0.92
Weighted average number of Trust Units:		
Basic	49,228,411	49,085,795
Diluted	49,228,411	49,093,609

See accompanying notes to consolidated financial statements.

($000s)	Year Ended December 31 2007	2006
Cash provided by (used in):		
Operating:		
Net income (loss)	$ (1,192)	$ 45,181
Items not involving cash:		
Depletion and depreciation	72,400	71,874
Trust Unit incentive compensation	631	290
Future income tax expense (reduction)	47,572	(100)
Accretion of asset retirement obligation	266	257
Trust Units issued in lieu of management fee	2,130	2,649
Expenditures on reclamation	(799)	(302)
	121,008	119,849
Changes in non-cash working capital (note 11)	(1,367)	10,986
	119,641	130,835
Financing:		
Long-term debt	78,000	(7,000)
Distributions paid	(94,524)	(108,471)
	(16,524)	(115,471)
Investing:		
Property and royalty acquisitions (note 4)	(90,456)	(5,382)
Capital expenditures	(12,167)	(11,446)
Change in reclamation fund	329	(153)
Changes in non-cash working capital (note 11)	(851)	1,846
	(103,145)	(15,135)
Increase (decrease) in cash	(28)	229
Cash, beginning of year	421	192
Cash, end of year	$ 393	$ 421

See accompanying notes to consolidated financial statements.

Basis of Presentation

Freehold Royalty Trust (the Trust) is an open-ended investment trust formed under the laws of the Province of Alberta pursuant to a Trust Indenture dated September 30, 1996 as amended from time to time. The Trust holds royalty interests directly and a 99% royalty interest in the funds generated by its wholly owned subsidiary, Freehold Resources Ltd. (Freehold Resources). Freehold Resources was incorporated on June 3, 1996 and derives its income from certain petroleum and natural gas working interest properties. The Trust also holds royalty interests and working interests through Petrovera Resources (Petrovera), a general partnership acquired on May 10, 2005.

These consolidated financial statements include the accounts of the Trust, Freehold Resources and Petrovera. All inter-entity transactions have been eliminated.

1. SIGNIFICANT ACCOUNTING POLICIES

(a) Petroleum and Natural Gas Interests:

The Trust follows the full cost method of accounting.

All costs of acquiring, exploring for and developing oil and gas and related reserves are capitalized. Such costs include land acquisition, geological and geophysical, carrying charges of unproved properties, costs of drilling both productive and non-productive wells, directly related administrative costs and asset retirement costs. Costs are reduced by proceeds from the sale of oil and gas properties and by government grants. Gains and losses are not recognized upon disposition of oil and gas properties unless such a disposition would alter the rate of depletion by 20% or more.

(b) Ceiling Test:

Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties.

The carrying amount is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount exceeds the sum of the discounted cash flows expected from the

production of proved and probable reserves, the lower of cost and market of unproved interests and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

(c) Depletion:

Oil and gas interests and royalty interests, including the costs of production equipment, future capital costs associated with proved reserves and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. Reserves are converted to equivalent units on the basis of relative energy content.

(d) Asset Retirement Obligations:

The Trust recognizes the fair value of an asset retirement obligation in the period in which it is incurred and when a reasonable estimate of the fair value can be made. The fair value of the estimated asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on a unit-of-production method over the life of the reserves. In periods subsequent to initial measurement, the passage of time results in liability changes and the amount of accretion is charged against current period income. The liability is also adjusted for revisions to previously used estimates.

(e) Income and Other Taxes:

The Trust is a taxable trust under the *Income Tax Act* (Canada) and it distributes substantially all of its taxable income to its Unitholders. The tax deductions received by the Trust for the distributions to Unitholders represent an exemption from taxation equivalent to the Trust's earnings.

The Trust follows the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. Freehold Resources can deduct royalty payments to the Trust in determining taxable income and is generally liable for income taxes on its 1% residual interest.

(f) Use of Estimates:

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses during the reporting period. Actual results could differ as a result of using estimates.

The amounts recorded for depletion of petroleum and natural gas properties and asset retirement obligations and amounts used in ceiling test calculations are based on estimates of petroleum and natural gas reserves and future costs to develop those reserves. By their nature, these estimates of reserves, costs, and related future cash flows are subject to uncertainty, and the impact on the financial statements of future periods could be material.

The Trust follows the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. The actual amount of future income tax may be greater than or less than the estimates and the differences may be material.

(g) Unit Based Compensation Plans:

A deferred trust unit plan has been established for the non-management directors of Freehold whereby fully-vested deferred trust units are granted annually. Under this plan, distributions to Unitholders declared prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of distribution. Compensation expense is recognized at the market value of the Trust Units at the time of grant or distribution with a corresponding increase to contributed surplus. Upon redemption of the deferred trust units for Trust Units, the amount previously recognized in contributed surplus is recorded as an increase to Unitholders' capital.

The Trust also funds its proportionate share of the costs associated with a long-term incentive compensation plan for employees of Rife Resources, the Manager of the Trust (the Manager's LTIP). The Manager's LTIP uses a combination of the value of phantom Rife shares and Trust Units as the basis for rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional rights on the date of distribution. Since participants in the Manager's LTIP receive a cash payment on a fixed vesting date, compensation expense is determined based on the intrinsic value of the rights at each period end. The valuation incorporates the period end Trust Unit price, the number of rights outstanding at each period end, and certain management assumptions. Compensation expense is recognized over the vesting period with a corresponding increase or decrease in liabilities. The Trust has not incorporated an estimated forfeiture rate for rights that will not vest; rather, the Trust accounts for actual forfeitures as they occur.

(h) Net Income Per Trust Unit:

Basic Trust Units outstanding are the weighted average number of Trust Units outstanding for each period. Diluted Trust Units outstanding are calculated using the treasury stock method, which assumes that any proceeds received from options with a market value in excess of option price would be used to buy back Trust Units at the average market price for the period.

(i) Revenue Recognition:

Revenue from the sale of crude oil, natural gas and natural gas liquids is recognized when title passes from the Trust, or the operator of the Trust's royalty properties, to its customers.

(j) Financial Instruments

On January 1, 2007, the Trust adopted the new Canadian accounting standards for financial instruments – recognition and measurement, hedging and comprehensive income. The new standards require all financial instruments within their scope, including all derivatives, to be recognized on the balance sheet initially at fair value. Subsequent measurement of all financial assets and liabilities except those held-for-trading and available-for-sale are measured at amortized cost determined using the effective interest rate method. Held-for-trading financial assets are measured at fair value with changes in fair value recognized in earnings. Available for-sale financial assets are measured at fair value with changes in fair value recognized in comprehensive income and reclassified to earnings when derecognized or impaired.

Cash and short-term investments, if any, are held-for-trading investments, and the fair values approximate their carrying value due to their short-term nature. Accounts receivable are classified as loans and receivables and accounts payable and accrued liabilities are classified as other financial liabilities and the fair values approximate their carrying value due to the short-term nature of these instruments. The Trust has not designated any financial instruments as available-for-sale or held-to-maturity.

The Trust did not identify any material embedded derivatives which required separate recognition and measurement.

2. NEW ACCOUNTING STANDARDS

Two new Canadian accounting standards have been issued that will require additional disclosure in the Trust's financial statements commencing January 1, 2008, regarding financial instruments, as well as capital and how it is managed. The Trust is in the process of evaluating the effects these standards will have on our financial statements.

3. PETROLEUM AND NATURAL GAS INTERESTS

($000s)	2007	2006
Petroleum and natural gas interests	$ 856,651	$ 751,485
Accumulated depletion and depreciation	(382,131)	(309,731)
Petroleum and natural gas interests, net	$ 474,520	$ 441,754

The depletion calculation included $0.6 million (2006 – $2.9 million) for estimated future development costs associated with proved undeveloped reserves and excluded $30.3 million (2006 – $19.4 million) for the lower of cost and market value of unproved lands.

The Trust's ceiling test calculation, performed at December 31, 2007, resulted in no impairment loss. The future prices used by the Trust in estimating cash flows were based on forecasts by an independent qualified reserves evaluator, adjusted for the Trust's quality, transportation, and contract differences. The following table summarizes the benchmark prices used in the calculation.

Year	WTI Crude Oil (US$/bbl)	Foreign Exchange Rate	Edmonton Par Crude Oil (Cdn$/bbl)	AECO Natural Gas (Cdn$/MMBtu)
2008	89.62	1.00	88.17	6.51
2009	86.01	1.00	84.54	7.22
2010	84.65	1.00	83.16	7.69
2011	82.77	1.00	81.26	7.70
2012	82.26	1.00	80.73	7.61
Average annual increase, thereafter	2%	–	2%	2%

4. PROPERTY ACQUISITIONS

On August 31, 2007, Freehold closed an acquisition of certain overriding royalty interests in Alberta and Saskatchewan for $57.6 million, net of adjustments. The acquisition is effective March 1, 2007, with results of operations being included from September 1, 2007.

On September 5, 2007, Freehold closed an acquisition of a gross overriding royalty interest on a property in Alberta for $32.8 million, net of adjustments. The acquisition is effective August 1, 2007, with results of operations being included from September 5, 2007.

Both acquisitions were funded through Freehold's credit facilities.

5. LONG-TERM DEBT

The Trust has a $195 million revolving term credit facility, extendible annually, on which $178 million was drawn at December 31, 2007. In the event that the lender does not consent to an extension, the revolving credit facility will revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period. In addition, Freehold has available a $15 million extendible revolving operating facility, undrawn at December 31, 2007. The facilities are up for renewal in May 2008.

Borrowings under the facilities bear interest at the Bank's prime lending rate, bankers' acceptance, or LIBOR rates, plus applicable margins ranging from 85 to 140 basis points, and standby fees.

The facilities are secured with $300 million demand debentures over Freehold's petroleum and natural gas assets.

6. ASSET RETIREMENT OBLIGATIONS

The Trust has no asset retirement obligations on its royalty interest properties. The Trust's asset retirement obligations result from its responsibility to abandon and reclaim its net share of all working interest properties. The net present value of the Trust's total asset retirement obligations are estimated to be $6.6 million (discounted at a weighted average credit adjusted risk free rate of 5.8%), with the undiscounted value being $23.6 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being more than 15 years away.

	December 31	
($000s)	2007	2006
Balance, beginning of year	$ 4,598	$ 4,036
Liabilities incurred	675	364
Liabilities settled	(799)	(302)
Revision in estimates [1]	1,868	243
Accretion expense	266	257
Balance, end of year	$ 6,608	$ 4,598

1. Revision in estimates is mainly a result of changes in estimates to well abandonment costs.

A reclamation fund, consisting of cash invested in an interest-bearing account, has been established and is funded by quarterly cash payments. All liabilities settled during the periods are paid from the reclamation fund.

7. UNITHOLDERS' CAPITAL

The Trust has authorized an unlimited number of Trust Units of which 49,316,813 were issued and outstanding at December 31, 2007 (2006 – 49,174,197).

TRUST UNITS ISSUED AND OUTSTANDING

	2007		2006	
	Number	Amount ($000s)	Number	Amount ($000s)
Balance, beginning of year	49,174,197	$ 562,698	49,031,581	$ 560,049
Issued in lieu of management fee	142,616	2,130	142,616	2,649
Balance, end of year	49,316,813	$ 564,828	49,174,197	$ 562,698

In May 2006 the Trust reserved an additional 800,000 Trust Units pursuant to its Management Agreement with the Manager, of which 173,293 have been issued.

The Trust is an open-ended mutual fund under which Unitholders have the right to request redemption directly from the Trust. Pursuant to the Amended and Restated Trust Indenture, Trust Units tendered by holders are subject to redemption under certain terms and conditions including the determination of the redemption price at the lower of the closing market price on the Toronto Stock Exchange on the date the Trust Units are tendered for redemption or 90% of the weighted average trading price for the 10-day trading period commencing on the tender date. Cash payments for Trust Units tendered for redemption are limited to $100,000 per month.

8. UNIT BASED COMPENSATION

(a) Deferred Trust Unit Plan

In May 2006, the Unitholders approved a deferred trust unit plan for non-management directors effective January 1, 2006. The plan consists of fully vested deferred trust units which are granted annually. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution. As at December 31, 2007 there were 30,473 deferred trust units outstanding which are redeemable for an equal number of Trust Units any time after the director's retirement.

DEFERRED TRUST UNITS

	December 31	
	2007	2006
Balance, beginning of year	12,559	–
Annual grant	14,181	11,165
Additional units resulting from distributions	3,733	1,394
Balance, end of year	30,473	12,559

For the year ended December 31, 2007, the Trust expensed $265,000 (2006 – $247,000) as unit based compensation, with a corresponding increase to contributed surplus.

CONTRIBUTED SURPLUS

($000s)		**2007**		**2006**
Balance, beginning of year	$	247	$	–
Trust Unit incentive compensation expense		265		247
Balance, end of year	$	512	$	247

(b) Manager's LTIP

In May 2006, the Board of Directors agreed to fund the Trust's proportionate share of a long-term incentive compensation plan for all employees of the Manager (the Manager's LTIP), effective January 1, 2006. The Manager's LTIP will result in employees receiving cash compensation in relation to the value of a specified number of notional units. The Manager's LTIP uses a combination of the value of phantom Rife shares and Trust Units as the basis for rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Distributions made by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. Upon vesting, the employee is entitled to a cash payout based on the Trust Unit price. In addition, there is a performance multiplier based in part on the Trust's performance over the vesting period, which may range from 0.25 to 1.5 times the market value.

At December 31, 2007, the Trust had accrued $1,106,000 (2006 – $129,000) as a long-term liability relating to incentive compensation pursuant to the Manager's LTIP and expensed $366,000 (2006 – $43,000) for the year then ended.

(c) Per Unit Amounts

For the purpose of calculating diluted net loss per Trust Unit for the year ended December 31, 2007, 28,507 incremental Trust Units from assumed redemption of deferred trust units are not included due to the anti-dilutive effect.

RELATED PARTY TRANSACTIONS

The Manager provides certain services for a fee based on a specified number of Trust Units per quarter, pursuant to a management agreement which has a term of three years and will be renewed on November 26, 2010 unless terminated. During 2007, the management fee paid was 142,616 Trust Units with an ascribed value of $2.1 million (2006 – 142,616 Trust Units with an ascribed value of $2.6 million).

During the year, the Manager charged the Trust $4.4 million (2006 – $3.7 million) in general and administrative costs. At December 31, 2007, there was $298,000 (2006 – $770,000) included in accounts payable relating to these costs. The transactions were in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the Trust and the Manager.

10. INCOME TAXES

Freehold Resources uses the asset and liability method of accounting for income taxes, as described in note 1. The provision for income taxes in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial tax rate to the Trust's earnings before income taxes. This difference results from the following items:

($000s)	**2007**	**2006**
Earnings before income taxes and capital taxes	$ 46,558	$ 45,372
Combined federal and provincial tax rate	32.7%	35.2%
Computed expected income tax expense	$ 15,234	$ 15,978
Increase (decrease) in income tax resulting from:		
Non-taxable earnings of the Trust	(14,024)	(15,337)
Non-deductible Crown charges	–	179
Resource allowance	–	(256)
Benefit of future rate reductions	(1,479)	(63)
Changes in enacted tax rates	(7,093)	(566)
SIFT legislated tax	54,798	–
Unit based compensation	134	–
Capital taxes	179	253
Other	2	3
Total income and capital taxes	$ 47,751	$ 191

Total income taxes are comprised of:

($000s)	**2007**	**2006**
Current income and capital taxes	$ 179	$ 291
Future taxes (reduction)	47,572	(100)
Total income and capital taxes	$ 47,751	$ 191

The components of Freehold Resources' future income taxes at December 31 are as follows:

($000s)	**2007**	**2006**
Future income tax liabilities:		
Petroleum and natural gas interests	$ 53,539	$ 5,295
Future income tax assets:		
Asset retirement obligations	(2,135)	(1,463)
Net future income tax liability	$ 51,404	$ 3,832

On a consolidated basis, the Trust's carrying value for book purposes exceeds the amount available for tax purposes by $244 million.

On June 22, 2007, Bill C-52 Budget Implementation Act, 2007, which contained legislation to tax certain publicly-traded specified income flow through (SIFT) entities in Canada, received Royal Assent and became law. As a result, a new 31.5% tax was to be applied to distributions from SIFT entities. The new tax is not expected to apply to Freehold until 2011 as a transition period applies to trusts that existed prior to November 1, 2006.

In December 2007, the federal government substantively enacted tax rate reductions, which lowered the corporate rates for 2008 to 20.5% with further yearly reductions to an ultimate rate of 15% in 2012 and future years. These rate reductions also lower the SIFT taxation rate from 31.5% to 29.5% in 2011 and to 28% in 2012 and future years.

11. SUPPLEMENTAL CASH FLOW DISCLOSURE

CHANGES IN NON-CASH WORKING CAPITAL BALANCE

($000s)	2007	2006
Accounts receivable	$ 3,048	$ 5,878
Accounts payable and accrued liabilities	(5,267)	6,954
	$ (2,219)	$ 12,832

CASH EXPENSES PAID

($000s)	2007	2006
Interest	$ 7,256	$ 5,294
Taxes	(690)	1,251

12. FINANCIAL INSTRUMENTS

The fair values of the Trust's accounts receivable and accounts payable and accrued liabilities approximate their carrying values due to their short terms to maturity.

The Trust is exposed to foreign currency fluctuations as crude oil prices received are referenced in U.S. dollar denominated prices.

The Trust pays interest on its long-term debt at prevailing market rates.

A large part of the Trust's accounts receivable are with oil and gas industry operators, either as joint venture partners or as payors of various royalty agreements. The Trust markets approximately 60% of its production along with the operator or royalty payor under the terms of a diverse number of agreements. When it can, the Trust takes its production in kind (currently 40%) and sells to two primary purchasers under normal industry sale and payment terms. None of Freehold's production is hedged.

corporate information

DIRECTORS
William W. Siebens, Chair [3]

D. Nolan Blades [1, 2, 3, 4]

Harry S. Campbell, Q.C. [2, 4]

Tullio Cedraschi

Peter T. Harrison [1, 2, 4]

P. Michael Maher [1, 2, 3]

David J. Sandmeyer

1. Audit Committee
2. Compensation Committee
3. Governance Committee
4. Reserves Committee

OFFICERS
William W. Siebens
Chair of the Board

David J. Sandmeyer
President and Chief Executive Officer

J. Frank George
Vice-President, Exploitation

Darren G. Gunderson
Controller

Joseph N. Holowisky
Vice-President, Finance & Administration and Chief Financial Officer

William O. Ingram
Vice-President, Production

Michael J. Okrusko
Vice-President, Land

Karen C. Taylor
Manager, Investor Relations and Corporate Secretary

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ANNUAL MEETING OF UNITHOLDERS
Wednesday, May 7, 2008
3:30 p.m.
Lecture Theatre
SunLife Plaza Conference Centre
2nd Level
140 - 4th Avenue S.W.
Calgary, Alberta

Unitholders who are unable to attend are requested to sign and return the form of proxy to ensure representation at the Meeting.

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Freehold

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